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February 17, 2015

By Electronic Mail

Clerk of the Board
California Air Resources Board
1001 I Street, 23rd Floor
Sacramento, CA 95812

Re: Proposed Amendments to the California Low-Carbon Fuel Standards Regulation and the Proposed Regulation of the Commercialization of Alternative Diesel Fuels

Dear Madam:

Growth Energy, an association of the nation's leading ethanol manufacturers and other companies who serve the nation's need for alternative fuels, is submitting to you the enclosed materials in response to the Executive Officer's notices of proposed amendments to California Low-Carbon Fuel Standards regulation and of the proposal to adopt a regulation for the commercialization of alternative diesel fuels. These materials also include environmental comments being submitted to the Air Resources Board and the Executive Officer pursuant to the California Environmental Quality Act and the Board's implementing regulations.

The Executive Officer has created separate rulemaking files and Board hearing agenda items for these two proposals. In view of the substantial overlap between these two proposals, including in the CARB staff's environmental assessment documentation, I ask that all of these materials, including the appendices and exhibits, be included in each rulemaking file and be considered by the Board in connection with each agenda item.

Growth Energy may file additional materials in one or both rulemaking files for consideration in connection with one or both agenda items at a later time, as permitted by the California Government Code.

If there are logistical questions concerning these submittals, please contact Mr. James M. Lyons of Sierra Research, Inc., at 916-444-6666.

Thank you for your consideration and assistance.

Sincerely,

David Bearden

David Bearden
General Counsel and Secretary

STATE OF CALIFORNIA

AIR RESOURCES BOARD

PROPOSED AMENDMENTS TO THE CALIFORNIA LOW CARBON FUELS STANDARD REGULATION AND THE PROPOSED REGULATION ON THE COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS

GROWTH ENERGY'S RESPONSE
TO THE NOTICES OF PUBLIC HEARINGS DATED DECEMBER 16, 2014
2015 CAL. REG. NOTICE REG. 13, 45 (JANUARY 2, 2015)

FEBRUARY 17, 2015

For further information contact:
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202-545-4000

Executive Summary

On January 2, 2015, the Executive Officer of the California Air Resources Board commenced the formal process of proposing amendments to the California low-carbon fuel standard ("LCFS") regulation and the adoption of a new regulation to govern commercialization of alternative diesel fuels used to comply with the LCFS regulation (the "ADF regulation"). Growth Energy shares CARB's goal of promoting alternative fuels that have lower greenhouse gas impacts than fossil fuels. In fact, promotion of this goal is central to Growth Energy's purpose. Unfortunately, Growth Energy believes that CARB's execution of the LCFS program as proposed would run counter to this goal. The proposal if finalized would promote the wrong fuels based on flawed, incorrect science, and as a result impose significant costs without accompanying greenhouse gas reductions. Thus, Growth Energy opposes adoption of the proposed amendments to the LCFS regulation and the currently proposed ADF regulation. Each regulation is unnecessary to achieve the environmental benefits sought by the California Legislature in the Global Warming Solutions Act of 2006, which is the statute on which the Executive Officer is basing his proposal.

The LCFS regulation is no longer needed to achieve the greenhouse gas reductions sought in the 2009 LCFS regulation, and Growth Energy has proposed a better alternative to the LCFS through the expansion of the existing cap-and-trade program. Since the Board first adopted the LCFS regulation in 2009, much has changed in efforts by the state and federal government to reduce greenhouse gas ("GHG") emissions from motor vehicles. Growth Energy presented a proposed alternative to the LCFS regulation to CARB staff in June 2014. Following review of Growth Energy's proposal, the CARB staff agreed with Growth Energy that Growth Energy's proposal would likely achieve the same level of GHG emissions reductions as the 2009 LCFS regulation through 2020. Growth Energy's proposal had none of the unintended negative environmental consequences of the 2009 LCFS regulation, which have been the subject of litigation, and would have eliminated the need for California businesses and consumers to pay for the LCFS program ─ costs which the CARB staff now says may range up to about 12 cents per gallon by 2020.

The new justification for the LCFS regulation ignores the federal renewable fuels program. The CARB staff rejected Growth Energy's proposed alternative to the LCFS regulation in the fall of 2014 because it claimed that by enforcing LCFS requirements now, CARB could prepare the California fuels market for further GHG reductions after 2020. The CARB staff theorized that only an LCFS program can adequately assure the diversification of the sources and methods of producing renewable fuels with low carbon emissions needed to achieve GHG reductions after 2020. When it rejected Growth Energy's proposal last fall, the CARB staff did not properly account for the beneficial effects of the federal renewable fuels standards ("RFS") program in stimulating fuels diversification and in the commercialization of cellulosic renewable fuels. The CARB staff still has not done so.

By disrupting the national market for renewable fuels, the LCFS regulation may increase global greenhouse gas emissions. Under the new LCFS regulation, corn ethanol produced at Midwest biorefineries will likely be displaced in large part by sugarcane ethanol from Brazil. Midwest corn ethanol biorefineries will be forced to choose between curtailing or shutting down production, or finding other markets for the ethanol that can no longer be sold in California. Because external economic factors constrain the output of the Brazilian sugarcane ethanol industry, and may continue to do so, the practical effect of the new LCFS regulation may be the shipment of Brazilian ethanol to California and Midwest ethanol to Brazil. The ethanol would travel on oceangoing tankers powered with fossil fuels. Intercontinental shipments of ethanol in response to California's regulation would have the unintended effect of increasing global GHG emissions.

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Comments of Growth Energy on Proposed Amendments to the California Low Carbon Fuels Standard Regulation and the Proposed Regulation on the Commercialization of Alternative Diesel Fuels

Growth Energy respectfully submits these comments on the proposed amendments to the low-carbon fuels standard ("LCFS") regulation and the proposed regulation on the commercialization of alternative diesel fuels. Growth Energy is an association of the leading ethanol producers in the United States and other companies that serve America's need for renewable fuels. As such, Growth Energy shares in a core goal of the LCFS program – the promotion of alternative fuels that lower transportation-sector greenhouse gas emissions, among other benefits. Growth Energy's comments for the California Air Resources Board ("CARB" or "the Board") are contained in this summary document and a number of appendices and exhibits. Growth Energy is combining in these comments its response to the notices of proposed rulemaking published for the LCFS regulation and the alternative diesel fuel ("ADF") regulation, which are both scheduled for a public hearing later this week, as well as its response to the consolidated draft Environmental Assessment ("the draft EA") for the LCFS and ADF proposals.[1]

Part I of these comments outlines some of the key statutory provisions that govern the LCFS and ADF rulemakings and identifies the CARB staff's serious shortcomings in complying with the same. Part II summarizes the analysis contained in the appendices to Growth Energy's comments on the lifecycle emissions analysis used in the LCFS regulatory proposal and the impacts of the LCFS proposal on consumers, businesses, and federal law and policy, as well as related issues. Part III and its accompanying appendices address the draft EA and other issues

[1] The public hearing notices dated December 16, 2014, and the draft EA were posted for public review and comment by the Executive Officer on January 30, 2014.

involving the environmental impacts of the two proposals and outline the Board's duties based on the record under the California Environmental Quality Act ("CEQA").[2] Part IV summarizes an alternative to the LCFS regulation that Growth Energy presented to the CARB staff, evaluates the CARB staff's response to Growth Energy's proposal, and describes the Board's legal obligations under the Government Code in light of the current record. Part IV also presents recommendations to facilitate the transparency and external review of the two current regulatory proposals.

I. STATUTORY FRAMEWORK AND BACKGROUND

The Board's consideration of the LCFS amendments and the proposed ADF regulation is governed by the California Government Code, the California Health & Safety Code, and CEQA, as well as the California and federal Constitutions. Pertinent requirements of CEQA and CARB's certified regulatory program to implement CEQA that apply to the draft EA are examined in detail in Part III and Appendix J of these comments. Because they are relevant to every aspect of these two rulemakings, it is important at the outset to identify three key provisions of the Global Warming Solutions Act of 2006 ("AB 32") and the Government Code that apply here.

Any regulation adopted by the Board must be consistent with and reasonably necessary to accomplish the purposes of AB 32. *See* Cal. Gov't Code § 11342.2. Three provisions of AB 32 are important to the Board's review of the CARB staff's proposal in order to determine whether the proposal is consistent with AB 32. First, regulations to implement AB 32 must not "interfere with … efforts to achieve and maintain federal and state ambient air quality standards" to the extent feasible, in addition to being adopted in a manner that complies with CEQA. Cal. Health & Safety Code § 38562(b)(4). Second, the emissions reductions that CARB attributes to an AB 32

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[2] Growth Energy may file additional materials not directly pertinent to the draft EA but relevant to other issues presented in the rulemaking prior to the start of the public hearings this week.

regulation must be "real, permanent, quantifiable, verifiable and enforceable." *Id*. § 38562(d)(1).[3] Third, AB 32 directs that the Board "shall" rely upon "the best available economic and scientific information" when adopting regulations to implement AB 32. *See* Cal. Health & Safety Code § 38562(e). For the reasons explained in these comments and the appendices, the proposed amendments to the LCFS regulation do not comply with those three central provisions of AB 32, and therefore the Board should not adopt them.

In addition, the Executive Officer cannot demonstrate that the LCFS amendments are "reasonably necessary" to meet the purposes of AB 32, as the Government Code requires. As the CARB staff admitted during the Department of Finance's review of the proposed amendments last fall, the LCFS regulation is likely not necessary in order to reduce greenhouse gas ("GHG") emissions prior to 2020; another, less burdensome alternative identified by Growth Energy would achieve those reductions and would not have the counterproductive impact on the California environment that the LCFS regulation will create.[4] In earlier comments to the CARB staff during development of the new LCFS regulation, Growth Energy explained that the limited purposes of the LCFS regulation were already accomplished by other programs. Having been presented with Growth Energy's alternative to the LCFS regulation, CARB cannot properly claim that no alternative to the LCFS program would be "as effective and less burdensome to affected private persons and equally effective in implementing the statutory purpose or other provision of law" — an averment required by section 11346.5(a)(13) of the Government Code, and which is important in protecting the public from unnecessary regulation. Remarkably, the Executive Officer's

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3 Notably, the requirements in subsection (d) of section 38562 are not qualified by the limitation in subsection (b), *i.e.*, "to the extent feasible."

4 Regarding those impacts, *see* Part III and Appendix I (Declaration of James M. Lyons).

December 2014 notice proposing the LCFS amendments does not even refer to the alternative measure proposed by Growth Energy, which was presented to the CARB staff in June 2014.[5]

The Legislature heightened the importance of evaluating alternatives to proposed regulations in 2011, when it amended the Government Code in order to require agencies to present their regulatory proposals to the Department of Finance for early review of costs, benefits, and alternative methods of accomplishing an agency's regulatory objectives. The LCFS and ADF rulemakings are among the first to be governed by the 2011 amendments, contained in SB 617. For the LCFS regulation, the CARB staff disabled meaningful stakeholder input into the SB 617 review by severely limiting the time permitted for regulated parties to participate, and by failing to fully disclose all the estimated benefits or costs of the proposed regulation (an omission that continues to this day). The shortfall in the SB 617 process for the ADF rulemaking was even greater: the version of the ADF regulation that the CARB staff submitted to the Department of Finance differed in material ways from the version of the ADF regulation that the CARB staff had under active consideration at the time of its SB 617 submission to Finance. Thus, the agency that the Legislature intended to have an active role in the development of major regulations in California — the Department of Finance — has never formally reviewed the key features of the ADF regulation. Unless the Board itself directs the CARB staff to comply with SB 617, it will be left to another agency (the Office of Administrative Law) to correct this egregious violation of SB 617.

In addition to mandating early review of regulatory proposals by the Department of Finance, the Legislature requires transparency in the rulemaking process, so that the public can

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5 *See* Appendix F and related exhibits.

participate effectively in that process. *See, e.g.*, Cal. Gov't Code § 11347.3; Cal. Health & Safety Code § 39601.5. The public rulemaking file required by section 11347.3 of the Government Code is critical to both transparency and public participation. Section 11347.3 requires, in essence, that the public have the same access to all the data and analysis used by an agency in developing regulations, as well as all external input provided to an agency in connection with the adoption or amendment of a regulation.

As indicated in Part IV of these comments, there are substantial questions concerning the Executive Officer's compliance with section 11347.3, in light of the sparseness of the CARB staff's documentation for key parts of its LCFS and ADF proposals. The CARB staff also waited until nearly the last possible moment to open the rulemaking file, which had the effect if not the purpose of limiting public analysis of the empirical and analytical basis for its proposals. While section 11347.3 of the Government Code applies to all California administrative agencies subject to the California Administrative Procedure Act (the "APA"), section 39601.5 of the Health & Safety Code was added to the Board's enabling statute in 2009 by AB 1085, when the Legislature learned of significant shortcomings in transparency in earlier rulemakings. Section 39601.5 compels CARB to provide "all information" on key aspects of its regulatory analysis "before the public comment period for any regulation" commences under the Government Code. It is unclear how the Executive Officer tried to comply with section 39601.5 in these rulemakings. What is clear, however, is that critical information about the assumptions and data on which the LCFS and ADF proposals are based has never been provided to the public.

II. REGULATORY ANALYSIS

The use of lifecycle analysis ("LCA") in assessing GHG emissions is at the heart of the LCFS regulation. The Legislature has directed that programs like the LCFS regulation rely on the "best available economic and scientific information"; notably, this mandate applies to the carbon intensity ("CI") values that CARB assigns to the various renewable fuels in the LCFS regulation, as well as to all other parts of the rulemaking.[6] The use of the most scientifically defensive CI values is critical to the rulemaking effort. The CI values provide what the 2009 Initial Statement of Reasons (ISOR") for the LCFS regulation called "signals" to the downstream fuel industry that will direct them to achieve reductions in the CI of the fuels they sell in the most cost-effective manner. Insofar as the intent of the LCFS regulation is to reduce GHG emissions, the regulation must establish "the maximum technologically feasible and cost-effective" method of doing so. Cal. Health & Safety Code § 38561(a). If the CI values send the wrong "signal" to the downstream regulated parties, then the LCFS regulation will result in the use of pathways that may increase GHG emissions above the levels that would result if the best possible CI values had been assigned to various renewable-fuel pathways in the regulation. As one witness affiliated with the University of California stated at the April 2009 Board hearing on the LCFS regulation:

> [I]f we make a mistake in one direction in estimating these numbers, we'll use too much of a biofuel that's actually higher carbon [than] we thought and will therefore increase global warming. And if we use numbers that are too low, then we'll use too little of a biofuel that's lower carbon than we thought and will therefore increase global warming.

Transcript of Public Meeting of the Air Resources Board, April 23, 2009, at 73-74. As explained in Appendices A, B, and C to these comments, and as summarized below, the "signals" that CARB's new California GREET 2.0 and indirect land-use change models provide for corn-starch, corn-stover and sugarcane ethanol do not reflect the best available scientific and economic

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[6] *See* Cal. Health & Safety Code § 38562(e). The Legislature has not directed CARB to use carbon intensity as a regulatory mechanism; that is a choice the Board made in the 2009 LCFS regulation and that the CARB staff proposes to continue.

information, and therefore do not provide the accurate “signals” to the downstream industry that are needed to maximize GHG reductions while minimizing costs. To adapt the 2009 formulation of the issue, quoted above: the “numbers” for sugarcane ethanol are “too low” and as a result, “too little” corn-starch and corn-stover ethanol would be used in California gasoline, if the Board adopts the staff’s proposal. (*See* Section A.1 & 2 below.)

In addition, if the currently-proposed regulation were to be adopted, the displacement of corn ethanol that would result will severely interfere – once again as in earlier years of the LCFS program – with the federal renewable fuels standard (“RFS”) program, in violation of federal law. No purpose is served by the State’s conflict with federal law, because as also explained below, the regulation of CI at Midwest corn-starch ethanol biorefineries serves no beneficial purpose; contrary to the staff’s claims in the current rulemaking, those biorefineries cannot and will not attempt to change their production methods solely to achieve lower CI scores in response to the LCFS regulation. In that particular respect the LCFS program violates an important tenet of AB 32, because it does not achieve “real” reductions in GHG emissions,[7] despite claims to the contrary. (*See* Section B below.)

A. The CARB Staff’s Lifecycle Emissions Analysis and its Consequences

1. Indirect Land-Use Change

From its inception, one of the most controversial aspects of the LCFS program has been its attempt to incorporate the theory of indirect land-use change (“ILUC”) into regulation.[8] The

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[7] *See* Cal. Health & Safety Code § 38562(d)(1).

[8] It remains Growth Energy’s position that the ILUC theory and the methods used to quantify the impacts of biofuel usage on land change, as well as the emissions model used by CARB to estimate emissions from land change, are too unreliable for use in regulation.

concept of ILUC stands at the intersection of environmental science and economics; having made the decision to try to use the ILUC theory in the LCFS program, CARB can be expected to comply with AB 32, and to use the "best available" scientific and economic information. As explained in Appendix A of these comments, the CARB staff has continued to ignore efforts by stakeholders to improve the quality of CARB's ILUC and indirect-emissions models, as well as recommendations of the Expert Working Group ("EWG") that CARB established when it first adopted the LCFS regulation. CARB must now finally address or adopt each of the recommendations presented in Appendix A, and in Growth Energy's other appendices to these comments, or explain fully why it is not doing so. *See* Cal. Gov't Code § 11346.9(a)(3). Insufficient time to address the recommendations in Appendix A is not sufficient justification for rejecting any of them; Growth Energy and other parties offered those recommendations before the staff published its current proposal and, in some instances, *at least four years ago*. (*See* Appendix A at A-2 and Table 1.) In the text below, Growth Energy summarizes some of the key deficiencies in the new ILUC analysis offered by the CARB staff for the Board's review.[9]

These are among the recommendations in Appendix A:

- *Price-yield response facto*rs. The CARB staff's ILUC analysis for corn-starch ethanol uses a range of price-yield values, despite recommendations from the

[9] Each Appendix to the main text of Growth Energy's comments are a fully incorporated part of Growth Energy's comments. The Board must respond fully to each objection and recommendation in the appendices to the main text of these comments, regardless of their placement, or, at a minimum, explain why it believes each of these objectives or recommendations to be "irrelevant." *See* Cal. Gov't Code § 11346.9(a)(3). To ensure compliance with that requirement of the Government Code, California courts will conduct *de novo* review using independent judgment. *Cf. POET LLC v. California Air Resources Bd.* (2013) 218 Cal. App. 4th 681, 747-48. Particularly when the facts concerning CARB's actions in the regulatory process cannot be a subject of genuine dispute, "the independent standard of appellate review" applies. *Id.* at 748.

authors of the model that CARB uses, as well as the EWG, that the most scientifically defensible value is 0.25. In the ISOR for the LCFS regulation, the Executive Officer relies on a non-peer-reviewed data review by a researcher at the University of California-Davis retained by CARB to support a lower price-yield value. In addition to lacking full documentation, the Davis reviewer appears to have made unexplained, selective use of other research, by Dr. J.F.R. Perez at Purdue University. The CARB staff has not supplied critical missing information from the Davis review requested by Growth Energy, and at this juncture, Growth Energy has no choice but to question whether the Davis review used reliable methods. Certainly, the Executive Officer cannot claim that the staff's work on price-yield responses has been transparent, nor that it is based on the "best available" information: information that is not made available to the public during a rulemaking governed by the California APA is akin to having no information at all.[10]

- *Multiple cropping*. Last year, researchers at Iowa State University ("ISU") published a study that compared the results of ILUC modeling using GTAP (the modeling system used by the CARB staff) with real data. The study showed that over the last 10 to 15 years, there has been no net land conversion from forest and pasture to cropland in many regions of the world. (*See* Appendix A, note 5.) The ISU study confirms that increases in crop prices (a theoretical result of biofuels mandates like the LCFS regulation) will result in multiple cropping. The CARB

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[10] If the Board directs the Executive Officer to provide the missing information concerning the Davis review, it must follow the procedures in section 11347.1.

staff has ignored that study in its rulemaking proposal and supporting materials. The CARB staff has also ignored a November 2014 submission by Growth Energy that demonstrated how the ISU work could be adapted to correct the results of GTAP. Since at least 2009, the CARB staff has known about the inability of GTAP to account for multiple cropping; Growth Energy supplied a method to correct that deficiency. If the CARB staff did not agree with Growth Energy's approach, it should have developed and applied its own. Choosing instead to completely ignore the ISU study violates the Legislature's requirement to use the "best available" information. If the staff's position is that it had too little time or resources to include the ISU work in its new proposal, then the solution is simple: the Board should give the staff the resources it needs and direct the staff to return to the Board, before the Board attempts to act on the current LCFS proposal.

- *CRP Land.* A lack of time or resources to update GTAP is also not a valid reason for the CARB staff's steadfast refusal to include the effects of the Conservation Reserve Program ("CRP") land in mitigating the land-use-related emissions impacts that the CARB staff attributes to corn-starch ethanol. In March 2014, Growth Energy supplied CARB with direct evidence from U.S. Department of Agriculture statistics showing that CRP land conversion has occurred in the last five years. The GTAP system already includes computer code to "access" CRP land, as Appendix A points out. In other words, CARB has a model that can account for CRP land conversion and was provided with CRP conversion data almost a full year ago. But apparently nothing has been done with this issue in the

CARB staff's new proposal, and the reasons why the staff has not done so are not clear in the materials provided to the public.

- *The AEZ-EF and CCLUB models*. The CARB staff's current LCFS proposal uses a model called the "Agro-ecological Zone Emission Factor" model (or "AEZ-EF") to estimate GHG release caused by various theoretical land transitions. In 2013, the researchers at the Argonne National Laboratory ("Argonne") released an updated version of an alternative model that serves the same purpose as AEZ-EF called the "Carbon Calculator for Land Use Change from Biofuels Production" model (or "CCLUB"). The 2013 CCLUB model includes more detailed emissions-related information for the United States than the AEZ-EF model. The land-use change emissions estimated with AEZ-EF and CCLUB differ substantially. (*See* Appendix A, Table 2.) Although the CARB staff has claimed in at least one stakeholder discussion to have evaluated CCLUB, there is no indication of its having done so in the AEZ-EF documentation, the ISOR for the current regulatory proposal, or the staff's accompanying materials. In order to determine whether the CARB staff is using the "best available" science, the Board and stakeholders are entitled to know why the CARB staff has chosen to use AEZ-EF rather than CCLUB.

The potential magnitude of the errors in the CARB staff's ILUC analysis, and thus in the "signals" concerning the CI of corn-starch ethanol created by the proposed new LCFS regulation, are large. These false signals threaten to undermine the very purpose of the LCFS by promoting fuels that will not necessarily reduce greenhouse gas emissions and may even increase emissions. Having now been provided with Appendix A to these comments ─ which largely restates various objections to the staff's current approach and corrective recommendations that Growth Energy has previously presented[11] ─ the Board can and must address these issues. If CARB relies on information not currently in the rulemaking to explain its reasons for not accepting Growth Energy's objections and recommendations, it must place that information in the rulemaking file and allow sufficient time for public review and comment. (*See* note 9 above.) If no such information is forthcoming, then the alternate explanation is that the Board is relying on conjecture and unsupported assumptions, rather than the "best available" information. Alternatively, if the Board is convinced that more time and resources are needed to address the issues presented in Appendix A, it should either suspend the LCFS program or maintain the regulatory status quo until the staff is prepared to bring a new proposal back to the Board.

2. California GREET 2.0

In Appendices B and C, Growth Energy comments on the portions of California GREET 2.0 ("CA GREET 2.0") used in the CARB staff's new LCFS proposal to generate direct-CI values pertaining to corn and sugarcane ethanol. There are several issues identified in Appendices B and C that CARB must address:[12]

- *Impacts of land-use change on methane emissions*. Enteric fermentation, which occurs in the digestive system of ruminant animals, produces methane, which AB 32 treats as a greenhouse gas. The models used in LCA analysis that attribute the creation of additional

[11] Some of the relevant earlier submissions by Growth Energy are included in Appendix A. Other stakeholders may have advanced similar objections and recommendations, or commented on the same issues. It is impossible to know if that has occurred, however, because the CARB staff has apparently interpreted the Government Code not to require it to have placed all such submissions in the rulemaking file for this proceeding. *See* Part V below.

[12] *See* note 8 above.

cropland to biofuel mandates also posit that the increase in cropland will reduce the land area available for grazing animals (unless additional land is cleared for grazing); one result of that reduction in grazing area, or a need to clear more land, will be an increase in livestock prices, a reduction in demand for meat, and smaller herds. As Appendix B notes, EPA's LCA analysis has accounted for this indirect reduction in methane emissions in the RFS program's LCA analysis. The CARB staff, however, has not done so in CA GREET 2.0 or in other parts of its new LCFS proposal, even those this omission has been repeatedly called to the staff's attention. Unless the CARB staff has a sound theoretical or empirical basis for disagreeing with EPA's judgment that a sound LCA-based program should account for the reductions in total methane emissions that will result from any land-use changes predicted from biofuels policies, the CA GREET 2.0 model should be modified to come into line with EPA's approach.

- *Credit for reductions in methane emissions resulting from the use of DGS*. Livestock fed with a coproduct of corn-starch ethanol production, called distillers grain solubles ("DGS"), experience lower rates of enteric fermentation and therefore release less methane. Accordingly, Argonne's current GREET model (called "GREET 1-2013") gives "credit" to corn-starch ethanol production that includes the production of DGS. By contrast, CA GREET 2.0 does not, ostensibly because the CARB staff does not consider the feeding of animals to fall within the LCA system boundary for corn-starch ethanol. In addition to running counter to the judgment of Argonne's experts, who included a DGS credit for reductions in methane emissions, the CARB staff's approach is arbitrary. The entire ILUC theory is itself based on economic assumptions that are untestable; if the theory itself is sound enough for inclusion in a regulatory program, then there is no reason to exclude the credits for DGS production recognized by Argonne.

- *Backhaul emissions.* In a regulatory program involving multiple fuel pathways, like the LCFS regulation, the LCA analysis must treat pathways that use different feedstocks in a consistent manner, unless there is sufficient basis to treat them differently. As Appendix C points out, of all the liquid fuels included in CA GREET 2.0, only one (ethanol made from sugarcane) is not charged with so-called "backhaul emissions," which are intended among other purposes to account the GHG emissions attributed to a vessel that has transported liquid fuel to a given destination after it departs for another port. In the case of sugarcane ethanol, which reaches the United States via ocean tankers, the omission of backhaul emissions has a significant impact on its assigned CI value. (*See* Appendix C, section 6.1.[13]) Consistency in the LCA analysis and in the regulatory process generally should require producers of sugarcane ethanol to account for those emissions in their applications, unless they can accurately and affirmatively show for purposes of their pathway application that no such backhaul emissions exist.[14]
- *Accuracy of inputs for shipping emissions for Brazilian sugarcane ethanol.* Basic information used in the LCA analysis must be accurate. As Appendix C indicates, CA

[13] A screen-shot of the relevant workbook from CA GREET 2.0 is included as an Exhibit to these comments.

[14] If the premise for assigning no backhaul emissions for sugarcane ethanol from Brazill is a belief that vessels that would carry sugarcane ethanol to the United States from Brazil would not leave the United States without a cargo, then (barring some explanation) the same premise should apply to the water transport of renewable diesel from the Far East, corn ethanol produced and used in the United States after barge transport, sugarcane ethanol transported by barge, and other fuels transported by barge that are included in GREET 2.0.

GREET 2.0 assumes that all sugarcane ethanol from Brazil is delivered in 22,000-ton shipments ─ an assumption that is not supported by the available data. (See Appendix C, section 6.2.) CA GREET 2.0's assumption likely understates GHG emissions from inbound ocean transport by 100 percent. CA GREET 2.0 also uses unrealistic, across-the-board assumptions about the relationship between oceangoing vessel power requirements and vessel speed. (*Id.*, section 6.4.) The appropriate course is to modify CA GREET to include default values based on the relevant real-world data (presented in Appendix C), which may be modified for pathways based on verifiable and enforceable certifications by the pathway applicant.

Appendices B and C identify additional inconsistencies, errors and failures to use the best available information in CA GREET 2.0. Two of the world's leading biofuels experts, Bruce Dale and Seungdo Kim of Michigan State University, have identified additional errors in CA GREET 2.0 for corn ethanol, as documented in Appendix B. Such errors violate the Legislature's mandate for the use of the "best available" information in AB 32 regulations, and those errors were presented and fully documented to the CARB staff in November 2014, shortly after a draft of CA GREET 2.0 was released for public review. The impact on the direct CI emissions factors is significant, especially for corn-stover ethanol, and those errors must be addressed without further delay. Likewise, Appendix C indicates that CA GREET 2.0 does not reflect actual sugarcane farming practices, along with other errors that must also be corrected now, before the rulemaking proceeds further. (See Appendix C, sections 2-5.) Unless those errors are corrected, the new LCFS regulation will provide significantly inaccurate "signals" to downstream regulated parties, and will not maximize the program's goals in a cost-effective manner.

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In sum, the CI values assigned to corn and sugarcane ethanol are not based on reliable data and methodologies, and need to be corrected before CARB tries to move forward with the LCFS "re-adoption" process. Although the CARB staff may believe that some or all the issues identified above cannot be addressed now, given their current regulatory schedule and claimed inadequate level of resources, the Board cannot accept such a position. The Board has discretion in setting the schedule to hear items for approval and to allocate CARB's resources, but under AB 32 it has no discretion to adopt or enforce regulations that are not based on the "best available economic and scientific information." Cal. Health & Safety Code § 38562(e). Again, applying CIs that are not based on the best available economic and scientific information threatens to undermine the very purpose of the LCFS.

B. Impacts of the Current LCFS Proposal

The incorrect regulatory "signals" created by the CI values assigned to corn and sugarcane ethanol will skew the California renewable fuels market away from corn-starch ethanol, and toward sugarcane ethanol. Corn-starch ethanol will not be able to compete with sugarcane ethanol using scientifically unreliable CI values. Among other consequences, this means that the potential increase of 13 cents per gallon of liquid fuel in 2020, estimated by the CARB staff if LCFS credits cost $100 per credit, will not be spent to achieve reductions in the CI of California motor fuels in the most cost-effective manner possible and may not lead to GHG reductions at all.[15]

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[15] The CARB staff's 13-cent-per-gallon estimate appears in the Attachment to the Form 399 (Fiscal Impact) report signed on December 15 and 16, 2014, by two CARB staff members, and which Growth Energy located in the rulemaking file at CARB in early January 2015. CARB uses the $100 per credit estimate in the ISOR for the LCFS. *See* LCFS ISOR at VII-1. According to the ISOR, the estimated fuel price increase for gasoline in 2020 using the $100 per credit estimate is 12 cents per gallon. *See id*. at VII-5, Table VII-5. While the CARB staff calls the $100 per credit estimate "conservative," considers the 12-cent-per-gallon estimate to "represent the upper bound of fuel price impacts," and urges that its estimates not be used to "determine the impact of credit prices on the final retail price of transportation fuels," *see id*.,

Despite the lack of corollary benefits, the new LCFS regulation will result in the displacement of corn-starch ethanol produced in the Midwest with other fuels. The staff has published an "illustrative compliance scenario" which projects a reduction in corn ethanol use in California gasoline from the current (2014) level of 1,250 million gallons per year to 700 million gallons per year in 2020, with an increase in consumption of cane ethanol equal to about 64 percent of that reduction. That scenario means a reduction in the use of Midwest corn ethanol in California of about 550 million gallons per year as of 2020, relative to today, equivalent to the entire output of about seven typical-sized ethanol plants.[16]

The CARB staff has based its analysis of the economic impact of the LCFS regulation from 2016 to 2020 ─ which is an analysis that is mandatory for any rulemaking governed by the APA, and whose reliability must be affirmed by the rulemaking agency before a final rule can be adopted[17] ─ on estimates of the prices of LCFS credits from 2016 to 2020. The primary case used in CARB's economic impact analysis uses, as indicated above, a $100 per credit price; the staff's analysis also examines economic impacts using lower credit prices. As explained in Appendix D, if sugarcane ethanol pathways achieve CI levels of 40 g/MJ, and corn-starch ethanol pathways achieve CI levels of 70, credit prices as low as $23 would be sufficient to induce a switch from

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the staff has not fully explained why it considers the $100 per credit to be "conservative" or why it believes the 12-cent-per-gallon increase to "represent the upper bound."

16 According to data published by the Renewable Fuels Association, the average output of operating corn-starch ethanol biorefineries in the United Sates is about 76 million gallons of ethanol per year. *See* www.ethanolrfa.org/pages/statistics.

17 *See* Cal. Gov't Code § 11346.5(a)(13) (requiring a determination of cost-effectiveness in an initial regulatory proposal); id. § 11346.9(a)(4)(same, in the Final Statement of Reasons for regulatory action). An agency cannot determine the cost-effectiveness of a regulation without estimating the costs of the regulation, as well as its benefits. As for the CARB staff's estimates of the benefits of the proposed new LCFS regulation, see Part IV below.

Midwest corn ethanol to imported sugarcane ethanol, assuming that the latter is available for sale to the downstream market in California. (That is an assumption that the CARB staff has made in its compliance and economic impact analyses.) As Appendix D, prepared by Edgeworth Economics, states, the CARB staff's "scenario indicating a substantial decline in the use of Midwest corn ethanol in California and an increase in the use of imported cane ethanol is therefore not only plausible, but probable if sufficient ethanol is available from Brazil, even at modest credit prices well below CARB's projected level of $100." CARB must explain whether, and if so, why, it considers this dramatic shift in the sourcing of ethanol for the California market (which its own staff's economic impact analysis confirms) to be irrelevant to its statutory mandates or objectives, and to the policies that it pursues as a matter of discretion.

Much, if not all, of the Midwest corn ethanol eliminated from the California market would be ethanol produced at biorefineries that generate renewable fuel that is certified under the federal Renewable Fuel Standard (RFS) with the specific intent of reducing national greenhouse gas emissions, thereby putting the LCFS program into direct conflict with federal law and policy.[18] In addition to the economic impacts on corn-starch ethanol business operations, the U.S. corn-starch ethanol producers who are currently attempting to finance the development of cellulosic ethanol production capabilities at plants located in the United States may have fewer resources available for those development efforts; in that respect, the LCFS program will further interfere with the goals and purposes of federal biofuels law and policy, which include the commercialization of cellulosic ethanol. Unless there is a significant expansion in domestic demand for ethanol, the increased imports of Brazilian cane ethanol, combined with the proposed LCFS regulation's

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[18] 42 U.S.C. 7545(o)(2)(A)(i)

generous allowance of credit to California electric utilities,[19] will result in a combination of (i) lost production or even shutdowns at Midwest biorefineries, and (ii) increased logistics costs as those American biorefineries seek foreign markets (potentially, and ironically, in Brazil, where ethanol is not subject to the LCFS regulation). If the Board believes that any other outcome or combinations of outcomes for the Midwest corn ethanol industry from the LCFS regulation will occur, it should explain them and estimate their likelihood of occurrence.[20]

The second outcome ─ corn ethanol export outside the United States to make up volume lost in California ─ will not produce reductions in global GHG emissions.[21] To the extent the first outcome (loss of any commercially practicable way to offset the reductions in California demand) occurs, then the LCFS regulation will have particularly grim consequences for the Midwest corn ethanol industry and those who depend on it. As Appendix D indicates:

> On average, U.S. corn ethanol facilities employ approximately 0.8 employees per million gallons of ethanol produced, or about 61 employees for a typical plant. A reduction in ethanol demand of 550 million gallons per year therefore would result in a direct loss of approximately 440 jobs at ethanol refineries. In addition to these direct effects, the regions that host ethanol production facilities would experience additional reductions in economic activity stemming from reduced purchases of locally-sourced inputs (the "indirect" impact) and reduced spending by facility employees and local vendors (the "induced" impact). These additional economic impacts are generated by the "multiplier" effect, which results from the recycling of business revenues and household income within the local region. Plausible estimates for the overall multiplier effect for employment applicable to the ethanol industry range from about 2 (indicating a total impact on employment equal to two

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[19] *See* Section C below.

[20] Note that this analysis of potential outcomes from the LCFS regulation assumes for present purposes that corn-starch ethanol pathways achieve the CI levels projected by the CARB staff. As to the realism of those projected reductions in CI levels, see Part III.A below.

[21] In addition to producing no net GHG emissions reductions, the second outcome will impose substantial direct costs on the Midwest corn ethanol industry. Appendix D estimates that the additional logistics costs for the transport of Midwest corn ethanol to a market like Brazil at approximately 10 cents per gallon.

> times the direct employment impact) to about 7. Applying a figure of 4 to the direct employment impacts calculated above implies a loss of approximately 1,760 jobs in ethanol producing regions.

If CARB disagrees with that assessment or considers those outcomes to be irrelevant to its mission, the Board needs explain why those impacts in the Midwest are overstated, or why those impacts are irrelevant.

III. ENVIRONMENTAL ANALYSIS

Two different statutes ─ AB 32 and CEQA ─ make it critical for the Board to develop a complete understanding of the environmental issues presented by the CARB staff's ADF and LCFS proposals. First and foremost, the purpose of AB 32 is to reduce GHG emissions, *see, e.g.*, Cal. Health & Safety Code § 38562(a); regulations that do not reduce GHG emissions are not "necessary" to meet the purposes of AB 32 and would violate the Government Code.[22] In addition, among other relevant requirements, including the obligation to rely on the "best available" scientific and economic information, *id.* §38562(e), AB 32 directs that to the extent feasible, the Board's GHG regulations not interfere with efforts to meet and maintain federal and state air quality standards. *See id*. § 38562(b)(4). Under CEQA and the Board's implementing regulations, the Board's obligations to protect the environment are, if anything, even more exacting: CARB "shall not" adopt or approve any action "for which significant adverse environmental impacts have been identified during the review process." if there are "feasible mitigation measures or feasible alternatives available which would substantially reduce such adverse impact." 17 C.C.R. § 60006.

As explained below, the CARB staff's two proposals do not meet the criteria of either AB 32, or of CEQA and the Board's implementing regulations. First, the CARB staff's LCFS proposal

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[22] *See* Cal. Gov't Code § 11342.2 ("no regulation adopted is valid or effective unless … reasonably necessary to effectuate the purpose of the statute").

assumes that the current LCFS regulations have actually reduced net GHG emissions into the atmosphere; in fact, there is no evidence that the LCFS regulations have done so, to date, and the available evidence demonstrates that there have been no such GHG reductions. Second, and building its first false premise about the efficacy of the current LCFS program, the staff's LCFS proposal invites a further assumption that the new LCFS regulations will achieve further reductions in net GHG emissions, but remarkably, the *staff has offered no definitive quantitative estimate of those GHG reductions.* That proposal also makes unrealistic assumptions about how portions of the affected industries will respond to the new regulation, and fails to account for ways in which the new regulation will increase, rather than decrease, GHG emissions, as well as criteria pollutants. The proposed new LCFS regulation cannot properly be treated as a regulation that meets the purposes of AB 32 because there is no reliable demonstration that the regulation will reduce GHG emissions, and the proposal is therefore not authorized by AB 32 and is invalid under the Government Code. In addition, and in conflict with section 38562(b)(4) of the Health & Safety Code, the CARB staff has ignored alternative, "feasible" methods of obtaining the same GHG reductions that it once attributed to the LCFS regulation through 2020. (*Id.*)

The staff's two proposals (for the new ADF regulation and for the revised LCFS regulation) also conflict with the requirements of CEQA and cannot be adopted. CARB is obligated to mitigate the significant adverse environmental impacts of the LCFS regulation recognized by the Court of Appeal in *POET v. California Air Resources Bd*. (2013) 218 Cal. App. 4th 681, that will result from the use of biodiesel fuels. As explained in Appendices I and J and as summarized below, the CARB staff's two proposals and the draft EA do not properly mitigate those impacts, or comply in other important respects with CEQA and the Board's implementing regulations.

A. The LCFS Regulation and GHG Emissions

We begin with the facts and analysis that are pertinent to an analysis of the LCFS proposal under AB 32, before turning to the CEQA analysis.

1. Background on Corn-Starch Ethanol Production: Past and Current Practices

The first step in understanding the environmental consequences of the proposed new LCFS regulation relevant to AB 32 is to consider the impacts of the current regulation, first adopted under AB 32 in 2009. The ISOR for the new proposed LCFS regulation claims that "[o]ver the first three years of the LCFS, there has been a steady decline in the average CI of the mix of biofuels used in California. Concurrently, there has been a great expansion of the applications for fuel-pathway CIs." (LCFS ISOR, App. B at B30.) On that basis, the "ARB staff expects these trends to continue and actually accelerate as the stringency of the LCFS increases and credits become more valuable." (*Id*.) The ISOR cites no facts in support of the staff's expectation, and its claim that there has been a "steady decline in the average CI of the mix of biofuels sold in California" is contradicted by the relevant evidence from the corn-starch ethanol industry. These are the pertinent facts: [23]

1. Ethanol produced from corn starch is the principal renewable fuel produced in the United States, and has been the primary alternative fuel blended into gasoline in California, both before and after the implementation of the current LCFS regulation. Members of Growth Energy and other producers in the U.S. corn ethanol industry have strong commercial incentives to

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[23] Because Growth Energy does not have access to confidential business information of its members or any other firms in the ethanol industry, it bases these comments on information in the public record. *See* Appendix E (Declaration of Erin Heupel, P.E. (hereinafter "Heupel Decl.").

maximize yield from the feedstock they purchase and to minimize energy usage, and thus to minimize GHG emissions. Next to corn costs, energy costs are the largest variable cost in producing corn ethanol.

2. A corn-starch ethanol plant costs millions of dollars to build. Most corn-starch ethanol is produced in the Midwest, at plants that are carefully sited in order to have ready access to their feedstock, as well as competitively priced natural gas, electricity, or other sources of energy to run the plant. Ethanol plants cannot directly control and document how farmers grow and harvest corn, which the farmers grow not only to sell to ethanol plants, but also to other customers, on the best possible commercial terms for the farmers. The companies that survive and prosper in the corn ethanol industry are those whose plants are designed from the beginning for maximum efficiency in feedstock conversion and minimum energy consumption.

3. The competitive pressure to reduce energy consumption, and not regulation, is what drives reductions in GHG emissions at corn ethanol biorefineries. For example, the current LCFS regulation has been in full effect since 2011; based on the information in the public record available to Growth Energy, ***no biorefinery*** selling ethanol for blending into gasoline has made ***any*** significant changes in its production methods, feedstocks, methods of transport, or any other factor relevant to GHG emissions, in order to specifically obtain a lower CI value for purposes of the California LCFS regulation. To be sure, as the ISOR claims, numerous plants have obtained approval for plant-specific "pathways" with lower CI values than might have otherwise been assigned to them under the California regulation. Those facilities, however, have obtained approval for those pathways by documenting production methods adopted for competitive reasons and federal policy reasons, completely independent of the California LCFS regulation.

Thus, when the ISOR claims that there has been a "great expansion" in the number of applications for new alternative-fuels pathways, in the case of Midwest corn-starch ethanol plants, it is confusing what are essentially paperwork exercises ─ when applicants are documenting production processes, methods and energy sources that have been adopted for commercial reasons ─ with reductions in CI levels driven by regulation. Because the record of "great expansion" in pathway applications appears to be one of the principal bases for predicting that the new LCFS regulation will result in reductions in the future, it is important for the CARB staff, and ultimately the Board, to identify any evidence that contradicts what Growth Energy has concluded from the information available in the open record.[24] Any such evidence should be then be placed in the rulemaking file pursuant to section 11347.1 of the Government Code for public review and comment. If, on the other hand, the CARB staff has no evidence the current LCFS regulation has driven reductions in the CI levels of corn ethanol plants in the Midwest, and the Board decides to act in reliance on the staff's speculation, then candor should require the Board to admit as much before work is completed on the new regulation.

Of course, not all corn-starch ethanol plants that were able to participate in the California market before 2011 have been able to remain in that market, because not all such plants have been able to document production processes, methods and energy usage that would qualify them for competitive CI values. When they have been able to remain in the market, they must generally

[24] As Appendix E indicates, Ms. Heupel of POET LLC, for her part, was able to describe the business and regulatory practice at her company in the open record. If the CARB staff believes that it cannot put any information that corroborates its position owing to concerns about business confidentiality, and that contradicts Growth Energy's understanding of how corn starch ethanol biorefineries have gained lower-CI pathways to date, it should so indicate, and include a description of its efforts to obtain permission from the owners of the putatively confidential information in the open record.

sell their product for less than what plants with lower CI values can obtain.[25] The CARB staff has admitted as much.[26] " Some of the plants that could not document the production technologies, processes, methods, and energy inputs that the CARB staff would reward with lower CI values had previously sold a substantial volume of ethanol in California," as one industry participant has stated, and "[t]he LCFS regulation forced some of those plants entirely out of the California market."[27] As the same industry participant has explained:

> The effect of the LCFS regulation has been to "de-commoditize" the corn ethanol market, for purposes of California -- *i.e.*, ethanol is no longer a fully fungible commodity in California, in which producers can prevail by offering the best commercial terms. Plants that were optimized for shipment of ethanol to California when they were built, but that can no longer sell their ethanol in California, now must find buyers outside California. On an industry-wide basis, the LCFS regulation has led to "fuel shuffling" that has likely increased the number of miles that Midwest corn ethanol had to travel in 2011 in order to get from the production facilities to customer destinations.

Whiteman Decl. ¶ 18. Importantly, as that individual concludes:

> For all the disruptions in the California ethanol market created by the LCFS regulation, there has been no reduction in the overall amount of corn ethanol produced in the United States, or used as a motor fuel in this country or overseas. …. The overall production levels for corn ethanol last year, and for the foreseeable future, depend on macroeconomic factors (including demand for gasoline) that are independent of the LCFS regulation.

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25 Growth Energy relies here on other public information. *See* Appendix E (Declaration of Robert Whiteman (hereinafter "Whiteman Decl.").

26 *See* Whiteman Decl. ¶ 17. Mr. Whiteman is a senior official in one of the largest ethanol marketing businesses in the United States, and would qualify as an expert on corn-starch ethanol marketing based on his knowledge, skill, experience and training.

27 *Ibid.*

Id. ¶ 20.[28] The CARB staff also agreed, in the 2009 rulemaking, that "fuel shuffling" would be one result of the current LCFS regulation. When taken together, the totality of the evidence thus establishes this important point: ***the current LCFS regulation has not resulted in any reductions in GHG emissions from corn starch ethanol,*** whose use in gasoline has been the downstream fuel industry's principal method of complying with the LCFS regulation.

In sum, and contrary to what may be the position taken in the ISOR for the new regulatory proposal, there has to date been no "real" reduction, see Cal. Health & Safety Code § 38562(d)(1), in the "average CI in the mix of biofuels used in California," at least with respect to liquid biofuels used in gasoline. Here again, if the CARB staff has any actual evidence contradicting Growth Energy's understanding of how the LCFS regulation has affected the corn-starch ethanol business to date, it must provide that evidence for review under the Government Code, or instead admit that it is asking the Board to rely on unsupported opinion.

2. Prospects for Future Reductions in the Carbon Intensity of Corn-Starch Ethanol

The ISOR also claims that the new LCFS regulation will continue the "trend" towards lower CI levels "as the stringency of the LCFS increases and credits become more valuable." (LCFS ISOR, App. B at B30.) The ISOR continues as follows:

> A two-step process was used to reflect how the trend to lower CI fuels will impact credit generation between 2016 and 2025. First, estimates of "pool-average" CIs for fuels with many different pathways were made based on the range of fuel-pathway CIs (FPCs) approved for use. The fuels studied were corn ethanol (150 FPCs), Cane Ethanol (21 FPCs), and Corn-Sorghum Ethanol (20 FPCs). In each case, the CIs of the lowest 50 percent of FPC CIs were averaged together, and this CI was then assigned (after appropriate adjustments to reflect iLUC changes) as the CI of that fuel category in 2016. Once a starting point for a fuel category's CI was determined for 2016, the CI was further lowered to reflect that higher credit values and continued plant improvements will lead to lower average CI with time. A

[28] Mr. Whiteman prepared his Declaration in 2012.

> conservative adjustment of a one percent decrease in CI values for each category was uniformly applied to at least partially recognize this effect.

Id. at B30-31. As the ISOR adds in a footnote, "For example the average CI of corn-derived ethanol under this method changes from 82.2 grams/MJ to 70.0 grams/MJ." Significantly, the ISOR here concedes that a substantial part of the industry current serving California ─ some or all producers who are in the upper half of the current FPC distribution ─ have no future in the California market. Also significantly, the ISOR offers no technical analysis or informed expert opinion to support the speculation that remaining ethanol production processes will achieve *on average* the first lower-CI level (for corn ethanol, 70.0 grams/MJ), and then year-over-year reductions.

In addition to lacking any apparent support, other than speculation by the authors of the ISOR, the ISOR's prediction for the future cannot be squared with what is currently known about industry conditions and the requirements of the proposed new LCFS regulation. As noted above (*see* Part II.B) and explained in Appendix D, at relatively modest LCFS credit prices, the LCFS regulation will shift demand for ethanol from corn-starch pathways to sugarcane pathways, and that shift will occur in the first year of the new program (2016). Here are some of the key facts that the ISOR's speculation about future "trends" does not address:

- The U.S. corn ethanol industry currently has enough production capacity to serve the Nation. The most competitive Midwest corn ethanol plants in operation today are built and sited for optimal logistics and energy usage in the first years of production, and not for significant future optimization.[29]

- In addition to energy, the corn feedstock is a major cost factor in corn-starch ethanol production, and corn-starch ethanol plants "cannot directly control and document how

[29] See Appendix E (Heupel Decl.).

farmers grow and harvest corn, which the farmers grow not only to sell to ethanol plants, but also to other customers, on the best possible commercial terms for the farmer."[30]

- Corn-starch ethanol plants are also assigned by the LCFS a large ILUC emissions factor, which they are powerless to change.

- Corn-starch ethanol plants can therefore work with only a fraction of their production processes ─ chiefly, energy, for which they are already likely optimized ─ to achieve lower CI scores.

- Any costs incurred to reduce the CI score of the ethanol that corn ethanol plants would produce would have to be recovered in the California market against competition from sugarcane ethanol and electricity. The deeper the reductions in CI, assuming any such reductions were possible, the greater the costs, and the longer the period needed to remain competitive in California.

Against that backdrop, Growth Energy credits the opinion expressed in Appendix E that in order to remain in the California market, "even a very efficient Midwest corn ethanol plant would have to find and implement further efficiencies or energy reduction opportunities not driven by the nationwide market and recover the costs of the necessary changes, over a very short time frame.… Rather than incur those costs, U.S. corn ethanol plants will try to compete in markets outside California."[31] Here again, if the CARB staff has any basis either to disagree with the prediction of market exist, or to support its belief in the "trend" that the ISOR predicts, it needs to provide the information (be it facts, expert opinion, or any other type of evidence) for public comment. If the CARB staff cannot do so, then as indicated above, candor requires the Board to admit that the predicted future operation of the LCFS regulation in the ISOR is based on unsupported conjecture, at least with respect to corn-starch ethanol.

[30] Heupel Decl. ¶ 10.

[31] *Id.* ¶ 11.

This issue ─ how the new LCFS regulation will affect the supply of cornstarch ethanol to California ─ needs to be addressed clearly, directly, and empirically. Corn starch ethanol remains a part of the CARB staff's compliance scenarios for many years; if corn starch ethanol cannot meet the expectations of the ISOR, then the viability of the new LCFS program as depicted in the ISOR is in serious jeopardy. If the absence of the corn starch ethanol from the California market triggers use of the cost-containment provision, as the costs of LCFS credits skyrockets, then LCFS program will not achieve the GHG reductions that CARB might otherwise attribute to the program.

3. Greenhouse Gas Emissions and Related Impacts of the New LCFS Regulation

Despite the ejection of corn-starch ethanol from the California renewable fuels market, the new LCFS regulation will not reduce, and will likely increase, net global GHG. As explained above, "fuel shuffling" is one likely outcome of the new LCFS regulation (accompanied by potential shutdowns of biorefineries in the Midwest). To date, the fuel shuffling caused by the LCFS regulation has been confined, in the case of ethanol, to the continental United States. The new LCFS regulation will make fuel shuffling an intercontinental phenomenon, as California begins to draw sugarcane ethanol in large quantities from production sites in Brazil. As explained in Appendix G, one result of the new regulation will be increases in GHG emissions caused by the transport of large volumes of Brazilian sugarcane ethanol to the California market. Looking solely at the GHG emissions increases that should be attributed to oceangoing tankers, fuel shuffling emissions will fall in the range of 385,000 to 735,000 tons of GHG emissions per year, under the assumptions described in Appendix G.[32] If the CARB staff or the Board have any disagreement with those estimated GHG shuffling losses, it should explain them and their basis.

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[32] *See* Appendix G. Those estimates are based on necessary corrections to the CA GREET 2.0 model, described in Appendix C. Even if those corrections are not made, GHG emissions from

For its own part, the CARB staff apparently has no current estimate of the net GHG emissions impacts of the LCFS regulation ─ at least, none that it was prepared to publish. The ISOR contains a table (Table IV-2) that contains some estimates of "Projected LCFS GHG Emissions Reductions." The ISOR prefaces that table, however, with this important qualification:

> These estimates do not include a reduction to eliminate the double counting of the Zero Emission Vehicle Mandate, the federal Renewable Fuel Standard Program, the Pavley standards, or the federal Corporate Average Fuel Economy Program. (LCFS ISOR at IV-2)

That is a breathtaking admission. Growth Energy is not aware of any other major regulation that the Board has ever been asked to approve without a net emissions reduction estimate for the pollutant or substance of primary concern (here, GHG emissions). For all that the Board and the public can tell, the programs that the ISOR has failed to include would leave the LCFS program with *de minimus* GHG emissions reduction benefits. Certainly, the current analysis before the Board does not meet the most basic tests for regulatory approval under AB 32; the GHG reductions that the proposed new LCFS regulation are not "quantifiable." Cal. Health & Safety Code § 38562(d)(1). Nor, of course, can the Board claim that the LCFS regulation would be "cost-effective," *see id.* § 38562(a), because there are no quantified GHG emissions reductions benefits to be placed into a ratio with the costs of the proposal. CARB cannot approve the new LCFS program proposed in the ISOR, without contorting the statutory language to allow it to impose costs on the public without first quantifying the GHG reduction benefits for which the public must pay.

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the transport of sugarcane ethanol by oceangoing tankers will rise by approximately 150,000 tons per year. *Id*. at 1.

There is no escaping the requirements of the rulemaking provisions in AB 32, and certainly none in other parts of the statute. AB 32 begins with legislative findings about the importance of addressing global warming, and urges coordination of California regulatory efforts with those of other jurisdictions. *See* Cal. Health & Safety Code § 38501(a),(b),(c),(f). Yet even if GHG reductions from the new LCFS program could be quantified, those reductions were assumed to be substantial, and they were assumed to extend nationwide ─ in other words, if every goal suggested by the statute's legislative findings were fulfilled ─ the end result would produce no appreciable effect on global warming. As explained in Appendix H, the difference in ambient temperatures could barely be resolved (in the third decimal place) by 2050, using the generally-accepted modelling system developed to assess the impacts of policies on global temperatures, and would be too small to be measured in the real world. In the 2009 LCFS rulemaking the CARB staff acknowledged this point, and suggested that the benefit to the LCFS program as a means of addressing climate change would lie in the export of the regulation outside California. Appendix H demonstrates that even under such an assumption, the LCFS program would not produce changes in the global climate. The LCFS program neither conforms with the rulemaking requirements of AB 32 nor serves the statute's highest aspirations.[33]

B. California Environmental Quality Act ("CEQA") Analysis

The core of Growth Energy's CEQA comments on the LCFS and ADF regulations is contained in Appendix I and its attachments, in Appendix J, and the other appendices specifically

[33] These observations on the lack of any change in the global climate resulting from the new LCFS program should not be taken to indicate that any regulation adopted under color of AB 32 could ever be exempt from the specific rulemaking requirements in section 38562 and other provisions of AB 32 that limit and specify CARB's authority.

referenced therein. The Board is required to consider detailed responses by the staff to each part of the Growth Energy's CEQA comments.[34]

1. Impacts of the Proposed Regulations on Criteria Pollutants

The ISOR for the ADF regulation estimates that the biodiesel use allowed by the ADF regulation, which will occur as part of efforts to comply with the LCFS regulation, will increase emissions of oxides of nitrogen ("NOx") by 1.35 tons per day in 2014 and according to the ISOR, will drop to 0.01 ton per day by 2023. Here are some of the salient problems in the ISOR for the ADF regulation and in CARB's draft EA, as explained in Appendix I and its attachments:

- The ISOR and its related documents do not describe the total diesel NOx emissions inventory on which the assessment is based.

- The CARB staff has erroneously concluded that the use of biodiesel in "New Technology Diesel Engines (NTDEs)" equipped with exhaust aftertreatment devices to lower NOx emissions will not lead to increased NOx emissions. The CARB staff has also incorrectly apply ratios of on-road vehicle travel by NTDEs from the now obsolete EMFAC2011 model to account for the amount of biodiesel used in all NTDEs including those found in non-road equipment.

- The CARB staff has incorrectly subtracted NOx reductions from the use of "renewable diesel fuel" from increases in NOx increases from biodiesel when assessing the environmental impact of ADF regulation.

- A conservative but reliable assessment of the NOx emission impacts of biodiesel use under the ADF that uses the latest CARB emissions models and corrects the flaws in the staff analysis has been performed for Growth Energy and is summarized in Appendix I (Lyons). The results of that assessment indicate that NOx increases from biodiesel will be much larger than those estimated by CARB staff and that the magnitude of the impacts will not decline as forecast by CARB staff.

- In addition, the assessment performed for Growth Energy demonstrates that the ADF regulation will lead to significant increases in NOx emissions in the South Coast and San Joaquin Valley air basins which are already in extreme non-attainment of the federal ozone NAAQS and moderate non-attainment of the federal fine particulate NAAQS.

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[34] *See* 17 C.C.R. § 6007(a)

- Inconsistencies and conflicts in the treatment of diesel and biodiesel fuels in the ADF and LCFS regulations create the potential for biodiesel blends to actually contain as much as 5 percent more biodiesel by volume than will be reported to CARB under the ADF regulation.

- Other errors in the CARB staff's environmental assessment include incorrectly selecting 2014 as the baseline year for the environmental analysis, a lack of documentation and use of unsupported assumption in determination of the NOx control level for biodiesel, and an unnecessary delay in the effective date for the implementation of mitigation requirements under the ADF regulation.

- Last year, during the development of the ADF and LCFS regulations, the CARB staff declined to adopt a proposed alternative to the ADF regulation submitted by Growth Energy. Given that the Growth Energy alternative was designed to mitigate all potential increases in NOx emissions, it yielded greater and more timely environmental benefits than the staff proposal. The Growth Energy alternative would have required the same mitigation methods as the ADF proposal but simply expanded the circumstances under which those methods must be applied; Growth Energy's proposal had a cost-effectiveness equal to that of ADF proposal.

2. CARB's Certified CEQA Program

CARB's certified program under CEQA does not excuse it from its obligations to address those serious deficiencies in the ADF proposal and the draft EA. Although "[e]nvironmental review documents prepared by certified programs," such as that adopted by CARB, "may be used instead of environmental documents that CEQA would otherwise require," "[c]ertified regulatory programs remain subject . . . to other CEQA requirements." *City of Arcadia v. SWRCB* (2006) 135 Cal.App.4th 1392, 1421-22. CEQA documents prepared under certified regulatory programs are considered to be the "functional equivalent" of the documents CEQA would otherwise require. *Mountain Lion Found. v. Fish & Game Comm.* (1997) 16 Cal.4th 105, 113.

Agencies with qualifying certified regulatory programs are excused only from complying with the requirements found in Chapters 3 and 4 of CEQA (*i.e.*, Pub. Res. Code, §§ 21100-21154) in addition to Public Resources Code § 21167. Pub. Res. Code, § 21080.5, subd. (c). "When conducting its environmental review and preparing its documentation," however, "a certified regulatory program is subject to the broad policy goals and substantive standards of CEQA."[35] The CEQA Guidelines implementing section 21080.5 provide that, "[i]n a certified program, an environmental document used as a substitute for an EIR must include '[a]lternatives to the activity and mitigation measures to avoid or reduce any significant or potentially significant effects that the project might have on the environment.'" (*City of Arcadia*, *supra*, 135 Cal.App.4th at 1422 [quoting CEQA Guidelines, § 15252(a)(2)(A)]. CARB's functional equivalent document is the "staff report," which "shall be prepared and published by the staff of the state board." 17 C.C.R., § 60005(a).[36] The regulations require the staff report to be "published at least 45 days before the date of the public hearing" on the rulemaking, and to "be available for public review and comment." (*Id.*) Staff reports must be prepared "in a manner consistent" "with the goals and policies of" CEQA, and "shall contain":

> a description of the proposed action, an assessment of anticipated significant long or short term adverse and beneficial environmental impacts associated with the proposed action and a succinct analysis of those impacts. The analysis shall address feasible mitigation measures and feasible alternatives . . . which would substantially reduce any significant adverse impact identified.

17 C.C.R. § 60005(b).

The regulations also provide that an action "for which significant adverse environmental impacts have been identified during the review process shall ***not*** be approved or adopted as

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[35] Kostka & Zischke, *Practice Under Cal. Env. Quality Act* (2005) § 21.10] ["Kostka & Zischke"] [citing *City of Arcadia*, *supra*, 135 Cal.App.4th at 1422; *Sierra Club v. State Bd. of Forestry* (1994) 7 Cal.4th 1215; *Californians for Native Salmon & Steelhead Ass'n v. Dept. of Forestry* (1990) 221 Cal.App.3d 1419; *Envt'l Protection Info. Ctr. v. Johnson* (1985) 170 Cal.App.3d 604, 616].)

[36] In this case, CARB's staff report is accompanied by a draft EA.

proposed if there are feasible mitigation measures or feasible alternatives available which would substantially reduce such adverse impact." *Id*. § 60006. "Feasible" means "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors, and consistent with the state board's legislatively mandated responsibilities and duties." *Id*) If CARB receives comments raising "significant environmental issues associated with the proposed action," staff must "summarize and respond to the comments either orally or in a supplemental written report. Prior to taking final action on any proposal for which significant environmental issues have been raised, the decision maker shall approve a written response to each such issue." *Id*. § 60007.

3. CEQA Analysis

Turning to the merits of CARB's current environmental analysis, and as explained in Appendix J, the draft EA does not comply with CEQA in several material respects.

First, the draft EA fails to consider the significant environmental effects associated with the version of the LCFS regulation currently in effect. Although the proposed LCFS regulation is nearly identical in structure to the current LCFS regulation, the draft EA fails to describe or identify impacts associated with the whole of the "project" under CEQA by ignoring recognized significant impacts associated with the existing regulation. Ignoring such impacts is inconsistent with the writ issued by the superior court in *POET, LLC v. California Air Resources Board* (2013) 218 Cal.App.4th 681 ("*POET*"), and results in a vague and incomplete project description. The draft EA also fails to state what environmental baseline is being used in its analysis, although the substantive discussions in the EA suggest a baseline of 2014 is being used. A 2014 baseline is inconsistent with Section 15125(a) of the CEQA Guidelines because it does not accurately reflect when CARB commenced its environmental review of the LCFS regulations (2007), and obscures the amount of NOx emissions caused by the increased usage of biodiesel resulting from the LCFS regulation. And even if CARB were able to credibly argue the current LCFS regulation is a different "project" than the nearly identical LCFS regulation proposed for "re-adoption," (1) analysis of pre-2014 impacts would nevertheless be required as "cumulative impacts," and (2) any attempt to ignore prior impacts would constitute impermissible piecemealing or segmentation of environmental review.[37]

The draft EA's analysis of criteria pollutant emissions caused by the proposed regulations is also incomplete. The draft EA fails to analyze or discuss emissions of any criteria pollutants, other than NOx. But even the discussion of impacts associated with NOx emissions, however, is misleading and fails to consider additional NOx emissions caused by increased biodiesel usage. CARB cannot argue increased renewable diesel fuel usage will offset NOx increases associated with biodiesel. This increase is speculative, and there is no mitigation, legally-binding requirement, or other performance standard to ensure those offsets will occur. The draft EA's analysis of criteria pollutant emissions is also incomplete because fails to analyze known sources of NOx emissions, including emissions associated with biodiesel use in "New Technology Diesel Engines" (NTDEs). Notably, if a more credible analysis of NOx increases using generally accepted techniques is employed, estimated NOx emissions are calculated to be far more severe than that disclosed in the draft EA, and could total as much as 9.73 tons per day statewide in 2020, and 2.39 tons per day (or 872.35 tons per year) in 2020 in the San Joaquin Valley air basin alone. This figure is vastly higher than the 10 tons per year threshold of significant adopted by the San Joaquin Valley Air Pollution Control District for projects under CEQA, and results in emissions

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[37] The two regulations under consideration are also internally inconsistent, as Appendix I explains. To avoid an unstable and inaccurate project description, and to avoid additional NOx impacts associated these inconsistencies (including but not limited to the blending of "Alternative diesel fuel" mixed with "CARB diesel"), the regulations must be revised and reconciled.

that directly violate the mandate of AB32. Cal. Health & Safety Code, §§ 38562 (b)(4), 38570 (b).

The draft EA also recognizes the proposed LCFS regulation would result in the construction of new or modified facilities to meet demand for fuels created by the regulations, including processing plants for agriculture-based ethanol, cellulosic ethanol, and biomethane. The draft EA, however, only generally describes the impacts associated with this increase in develop, although it is feasible to calculate the projected additional emissions associated with such development. Although the draft EA performs no analysis of the impacts associated with these facilities, it finds the impacts to be significant and unavoidable. This is impermissible; a lead agency cannot simply label an impact "significant and unavoidable" without first providing a discussion and analysis. *Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs* (2001) 91 Cal.App.4th 1344, 1370.

The failure to quantify the impacts associated with such new construction also violates CEQA because it forecloses mitigation. If the impacts were quantified, CARB could meaningfully explore ways to develop mitigation to reduce such impacts or modify the regulation to reduce those impacts. Instead, the draft EA merely sets forth "recognized practices" that are "routinely required" to avoid or minimize impacts, without requiring the implementation of any specific measure, or even evaluating whether any such measures – if incorporated – would actually reduce or minimize the impact. This is improper under CEQA because the proposed mitigation measures are not required or otherwise enforceable, there is no discussion as to the efficacy of any measure, there is no quantification of the benefits associated with any measure, and the specific mitigation to be employed is deferred to a later time.

The draft EA also fails to identify and analyze environmental impacts associated with fuel shuffling, which CARB has elsewhere recognized as a reasonably foreseeable consequence of the LCFS regulation. For one component of the LCFS regulation – shuffling of ethanol alone by ship – shuffling would result in at least an additional 150,000 tons per year of CO2 equivalent emissions using CARB's own models, and an additional 385,000-735,000 tons per year using more accurate models. These figures do not even take into account ethanol shuffling by other modes of transportation, or crude oil shuffling. There is likewise no analysis as to whether fuel shuffling would result in increases in criteria pollutants either in-state or out-of-state.

The draft EA also fails to adequately analyze project alternatives. For example, the draft EA rejects the Growth Energy alternative, even though the alternative would significantly reduce NOx emissions associated with biodiesel. The draft EA also impermissibly rejects consideration of a Cap & Trade Alternative, even though that alternative would result in none of the numerous impacts the EA found to be significant and unavoidable. The CEQA Guidelines specifically recognize that comments raised by members of the public on an environmental document are particularly helpful if they suggest "additional specific alternatives . . . that would provide better ways to avoid or mitigate the significant environmental effects," CEQA Guidelines, § 15204, and CARB may not limit its project objectives in a way to foreclose consideration of any and all projects, with the exception of the project under consideration. It was exactly this type of pre-judgment that the Court of Appeal warned against in the *POET* decision in its discussion of *post hoc* environmental review, and impermissible delegation of environmental review authority.

In sum, CEQA places the burden of environmental investigation on government rather than the public," and the draft EA falls well short of a complete and accurate investigation of the environmental effects of the proposed regulations. *Sundstrom v. County of Mendocino* (1988) 202

Cal.App.3d 296, 311. As a result of these failures, the EA must be revised substantially, and recirculated for public review, prior to CARB's consideration of the proposed regulations for adoption.

IV. THE BOARD'S GOVERNMENT CODE AND RELATED OBLIGATIONS

Addressing the deficiencies in the draft EA and the CARB staff's related environmental materials identified in Part III above and in Appendices I and J will require significant time and resources, if the Board decides to proceed with rulemaking based on the currently proposed regulations. Simultaneously with that effort, the Board also needs to consider whether there are less burdensome alternatives to the current staff proposals, as the Government Code requires, and also address serious problems in the transparency of the current rulemaking process. CARB's tasks under CEQA and the Government Code substantially overlap, because Growth Energy has proposed an alternative to the current LCFS regulation that would eliminate the need for NOx mitigation and thus greatly simplify the CEQA effort, while also reducing the costs and burdens of attaining the identified goals of AB 32.

A. The Analysis of Alternatives under the Government Code

The Legislature regularly gives California administrative agencies wide discretion in achieving the purposes of the statutes it enacts, but it also requires that agencies avoid unnecessary or unduly burdensome regulation. Agencies cannot first propose regulations unless they have determined that no alternative to their own proposal would be "as effective and less burdensome to affected private persons and equally effective in implementing the statutory purpose or other provision of law." *See* Cal. Gov't Code § 11346.5(a)(13). Nor can an agency finally adopt its own proposal unless it can properly affirm and explain, with "supporting information," that "no alternative" that it has considered "would be more effective and less burdensome to affected private persons than the adopted regulation, or would be more cost effective to affected private persons and equally effective" in meeting a legislative objective. *Id*. § 11346.9(a)(4).

There is no question that the proposed LCFS and ADF will impose costs on "private persons" and businesses in California, of as much as 13 cents per gallon by 2020, depending on the costs of LCFS credits. (*See* Part II.B above.) Growth Energy responded to the staff's call in the spring and summer of 2014 pursuant to SB 617 for the submission of alternatives to the current LCFS regulation, and what was understood about the developing proposed amendment to the LCFS regulation, as well as the developing proposed ADF regulation.[38] The threshold question that the Board must therefore address is whether it considers itself bound by the Government Code to consider Growth Energy's proposed alternatives to what the CARB staff has now proposed. If the Board believes it has no such obligation, Growth Energy requests that CARB explain its reasons, and specify the deficiencies in Growth Energy's proposed alternatives.

1. The Apparent Goals of the LCFS Program

Assuming that the Board agrees that it needs to consider Growth Energy's alternatives under the Government Code, the next task is to determine what benefits the CARB staff is claiming for its LCFS proposal. In that regard, the SB 617 process in 2014 was illuminating. Growth Energy's proposal would have required, depending on the CARB staff's view on the need to control upstream GHG emissions associated with the use of biofuels in California, an amendment to the current AB 32 cap-and-trade regulation applicable to the transportation fuels section.[39] The

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[38] *See* Appendix F.

[39] *Ibid.*

CARB staff responded as follows in the Consolidated Standardized Regulatory Impact Statement ("CSRIA") for the LCFS and ADF proceedings:

> ARB is required to analyze only those alternatives that are reasonable and that meet the goals of the program as required by statute. An initial assessment of the program indicates the goals of the LCFS proposal can be achieved by keeping the program '…separate of the AB 32 Cap-and-Trade system initially (at least first 10 years) in order to stimulate innovation and investment in low-GWI [global warming intensity] fuel (or transportation) technologies.' Due to the strong justifications that the Cap-and-Trade program alone generates neither the CI reductions nor fuel in the transportation sector, this alternative will not be assessed in this document.

CSRIA at 27 (footnote omitted.). Importantly, the CSRIA conceded that Growth Energy's proposed alternative would "likely" achieve the same "estimated GHG emissions reductions" as the current regulation in the period up to 2020. (*Id*. at 26-27.)

The deficiency in the Growth Energy proposal, according to the CSRIA, was not that it created a GHG emissions reduction shortfall at any point prior to the end of the current regulatory horizon; instead, the problem is that the Growth Energy proposal did not rely on the same purported strategy of fuels diversification and achievement of GHG emissions reductions as proposed by CARB. As Appendix A of the CSRIA explained:

> Transportation in California was powered almost completely by petroleum fuels in 2010. … Transitioning California to alternative, lower-carbon fuels requires a very focused and sustained regulatory program tailored to that goal. … In the absence of such a program, post-2020 emissions reductions would have to come from a transportation sector that would, in all likelihood, have emerged from the 2010-2020 decade relatively unchanged. ***In the absence of an LCFS designed to begin the process of transitioning the California transportation sector to lower-carbon fuels starting in 2010, post-2020 reductions would be difficult and costly to achieve.*** This is why the primary goals of the LCFS are to reduce the carbon intensity of California fuels, and to diversify the fuel pool. A transportation sector that achieves these goals by 2020 will be much better positioned to achieve significant GHG emissions reductions post-2020.

CSRIA at 27 (emphasis added). In essence, the CSRIA claimed that fuels diversification and carbon intensity requirements were necessary in order to make post-2020 greenhouse gas reductions less costly and less difficult to achieve. The text of AB 32 does not itself require the use of a fuels diversification strategy or CI indexes to achieve GHG reductions, and certainly does not mandate the use of regulations intended to reduce the carbon intensity of transportation fuels to achieve greenhouse gas reduction, in order to achieve "the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions." Cal. Health & Safety Code § 38562(a). If the Board believes otherwise, Growth Energy requests that CARB identify the statutory text within AB 32 that requires the creation of a fuels diversification strategy or the use of CI regulations to reduce GHG emissions.[40]

Assuming the CARB staff's position on the need for a LCFS program now (*i.e.*, from the present time until 2020) must be linked back to the purpose of AB 32 (which is to reduce GHG emissions), the staff's position seems to be that the regulation of the carbon intensity of transportation fuels is necessary now in order to reduce the costs or difficulties of achieving greenhouse gas reductions after 2020. Certainly, the CARB staff cannot defend its current proposal on the basis of any GHG reductions it will achieve: as noted in Part III.A.3 of these comments, the CARB staff has apparently abjured any effort to quantify the GHG reductions that the new LCFS regulation will achieve, either before or after 2020. In other words, the current LCFS program, stripped to its essential purposes, is not a measure to achieve any quantity of GHG

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[40] The CSRIA identified a white paper published in 2008 by researchers at the University of California (Davis) as support for the CARB staff's position on the need for CI-based regulations. If CARB believes that the 2008 white paper bears on the scope of its authority or discretion under AB 32, it should explain why.

emissions reductions over an identified time period; it is a measure to prepare California to achieve some unspecified quantity of GHG reductions at some time in the future.

2. The Requirements of Section 11346.9(a)(4)

As also indicated in Part III.A.3 of these comments, absent some "quantifiable" GHG emissions reductions, a regulation adopted under color of AB 32 is not within the scope of CARB's authority; the proposed new LCFS regulation is therefore invalid under section 11342.2 of the Government Code. Even CARB were to take a different view of the scope of its authority under AB 32, the Board would still need, under the California APA, to prove that Growth Energy's alternative does not meet the criteria of section 11346.9(a)(4).[41] The CARB staff has given the Board no basis for claiming to have so proved. Several points are important on this issue.

First, as Growth Energy pointed out in its SB 617 proposal last year, the federal renewable fuels program provides for the production and sale of cellulosic and "advanced" biofuels in the same time frame as the LCFS regulation. While the federal program does not require the use of electricity or hydrogen as a transportation fuel, the California motor vehicle emissions control and zero-emission vehicle programs (also noted in Growth Energy's proposal) certainly do.[42] The record in this rulemaking is devoid of any demonstration that the LCFS program will increase fuels diversification more than the federal RFS program and the State's electric-vehicle and related

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[41] The text of the APA makes it clear that the agency has the burden of proving "with supporting information" that no alternative considered by the agency would meet the criteria of section 11346.9(a)(4). If the Board does not agree that it has that burden, it should explain why not. In addition, the Board should articulate the standard that it believes would apply to judicial review of the determination required in section 11346.9(a)(4), and explain its full basis for choosing that standard.

[42] *See* Appendix F (Growth Energy's proposed alternative to the LCFS regulation, describing the programs that will achieve the fuels diversification sought by CARB, in the absence of the LCFS regulation).

programs will. To the contrary, the CARB staff has admitted that it is "unclear to what degree" the LCFS program will require "new production" of "less carbon-intensive fuels … in California or elsewhere."[43] If the record currently contains an analysis that estimates the increase in fuels diversification that the LCFS regulation will achieve compared to the federal RFS program, CARB should identify.

Second, as should be clear from the ADF ISOR and in the ADF ISOR's accompanying materials, the use of the CI-based regulatory strategy that the CARB staff is recommending will impose costs on the California motoring public, if they bear any costs of the mitigation strategy that the use of the LCFS regulation will require. As Growth Energy has demonstrated in Part III.B and the related Appendices, those costs may be even greater if CARB adheres to its duties under CEQA (though the cost-effectiveness of the mitigation strategy will not change). In addition, the increases in GHG emissions entailed in moving sugarcane ethanol to California (see Part III.A and Appendix G) will likely need to be offset by other types of GHG controls, which will impose additional costs on California consumers and businesses. The CARB staff has not offered any analysis to the Board that explains why those ***present*** costs, along with the direct costs of the LCFS program in the near term, are worth incurring in order to make the ***future*** costs of post-2020 GHG emissions reductions less costly. Conclusory or self-serving statements by businesses who claim that they will construct facilities or produce and market advanced, diversified liquid biofuels are entitled to no weight.

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43 *See* LFCS ISOR Appendix E at E-5.

Third, the long-run, post-2020 plans for GHG reductions developed by CARB call for the phase-out of reliance on liquid biofuels;[44] low-CI liquid fuels, however, are presumably the fuels whose production is in need of diversification, according to the CSRIA. Eventually, the State plans to eliminate gasoline, in particular, from use in California cars and trucks and to fully replace gasoline with electricity. Putting to the side whether CARB's post-2020 strategy is meritorious, the CARB staff has given the Board no basis to explain why CARB should impose costs on California consumers and businesses to foster the use of fuels that (according to CARB) are destined for a diminishing, and no long-term, role in its greenhouse gas reduction strategy.

One other important, procedural point must also be noted here. The demonstration required by section 11346.9(a)(4) that there are no superior alternatives to a proposed regulation (as the statute defines superiority) must be based on "supporting information." At present, there is no such "supporting information" in the rulemaking file of which Growth Energy is aware, perhaps because the CARB staff has looked ahead to the Board's obligations under section 11346.9(a)(4) of the Government Code. If the Board intends to add such information to the rulemaking file in order to try to carry its burden under section 11346.9(a)(4), it must comply with section 11347.1 of the Government Code.

In sum, with regard to the LCFS proposal, CARB is not currently positioned to proceed with final rulemaking because, among other reasons, it cannot discharge its obligations under section 11346.9(a)(4) of the Government Code. If the Board intends to pursue the staff's proposal, it must address the issues raised here, both substantive and procedural.[45]

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[44] *See* http://www.arb.ca.gov/planning/vision/vision.htm.

[45] If the Board does not agree with Growth Energy's analysis of the obligations of section 11346.9(a)(4), Growth Energy requests that the Board explain its reasons for disagreement.

B. Requirements of Transparency

Section 11347.3 of the Government Code requires CARB to maintain a "file of [the] rulemaking proceeding" for any proposed regulatory action subject to the APA, including the LCFS regulation." The rulemaking file must include, among other items, the following:

> (6) All *data and other factual information***,** any studies or reports, and written comments submitted to the agency in connection with the adoption, amendment, or repeal of the regulation.
>
> (7) All data and other factual information, *technical, theoretical*, and *empirical studies or reports*, if any, on which the *agency is relying* in the adoption, amendment, or repeal of a regulation, including any cost impact estimates as required by Section 11346.3.

Gov't Code § 11347.3(b)(5),(6) (emphasis added). The entire rulemaking file, including the foregoing material, must be "available to the public for inspection" from the time when the first notice of the proposed rulemaking is published in the California Regulatory Notice Register, *id.* at § 11347.3(a), which here occurred on January 2, 2015.

As the above-quoted text makes clear, rulemakings at CARB must include the creation of a rulemaking file that includes "***[a]ll*** data and other factual information, any studies or reports, and written comments submitted to the agency" in connection with the proposal. Gov't Code § 11347.3(a),(b)(6) (emphasis added). To assure immediate public access to the supporting materials as soon as the 45-day materials are released, the APA requires that the 45-day notice include a statement that the agency on the date of the notice "has available *all* information upon which [the] proposal is based." *Id*. § 11346.5(a)(16) (emphasis added). A separate provision confirms that the agency must in fact make those records, and any other "public records, including reports, documentation, and other materials, related to the proposed action," available. *Id.* § 11346.5(b).

The "written comments" that must be placed in the record are not simply those submitted to the agency in a particular manner or at a particular time, such as during the period between publication of the notice of a public hearing and public hearing -- an agency must put "all" it receives "in connection with" a regulatory proposal in the rulemaking file. The Legislature's choice of words to describe what comments must be placed in the file -- "in connection with" -- sweep with intentional breadth, and require inclusion of any comments that bear on the subject of the regulatory effort. In addition, the period of public availability must "[c]ommenc[e] *no later than* the date that the notice of the proposed action is published." *Id.* § 11347.3(a) (emphasis added). The use of the term "no later than" makes it clear that the Legislature expected written comments submitted in connection with a proposed regulatory action and received before publication of the required notice to be included in the rulemaking file.

Growth Energy has substantial concerns about the completeness of the rulemaking files for the current LCFS and ADF rulemakings, as it did in the prior LCFS rulemaking in 2009. The Court of Appeal made clear in *POET v. CARB* that neglect to include even a limited number of relevant documents in the rulemaking file would violate the Government Code. To avoid further controversy, Growth Energy requests that the Executive Officer or the CARB legal staff consider and respond to the following questions:

1. Does the CARB legal staff agree that the rulemaking file for these two proceedings must include external communications submitted to the staff, the Executive Officer or the Board prior to the date when the rulemaking file is formally opened must be included in the rulemaking file, if those communications were submitted in connection with the adoption or amendment of ADF and/or LCFS regulation? Conversely, does the CARB legal staff believe that no such external communications submitted before the rulemaking file would come within the definition of records

required for inclusion in the file, pursuant to section 11347.3(b)(6)? Are there any written guidelines or instructions used by the CARB staff to determine whether a communication submitted before the file is opened must be included in the file? Are there any written guidelines or instructions that the CARB staff uses in order to determine what constitutes "data … other factual information … studies or reports," or "written comments," that should be included in the rulemaking file? Will any such guidelines or procedures be made available?

2. The ADF rulemaking was opened in 2013 and then pretermitted in 2014. What steps have been taken to assure that that all external submittals (not within the scope of section 11347.3(b)(7) concerning the 2013-2014 regulatory process were included in the ADF rulemaking file opened in January 2015? If the CARB legal staff believes that no such external submittals before January 2015 were required to be included in the "new" rulemaking file, was there any process by which the public could obtain prompt access to those materials?

Turning to the requirements of section 39601.5 of the Health & Safety Code, as noted in Part I, the Legislature in AB 1085 directed CARB to provide "all information" on key aspects of its regulatory analysis "before the public comment period for any regulation" commences under the Government Code. Growth Energy requests that the CARB legal staff explain what steps were taken to provide all the information covered by section 39601.5 in connection with the current LCFS and ADF rulemakings. Growth Energy requests that each document or other file made available to the public under section 39601.5 prior to January 2, 2015, in connection with these two rulemakings be identified, along with the date it was made available and the method by which it was made available.

C. The SB 617 Process

As the correspondence included in Appendix F makes clear, the version of the ADF proposal on which the CARB staff invited comment and responses in the SB 617 process in 2014 differed materially from the version of the ADF proposal that the CARB staff was discussing with some stakeholders, and that the CARB staff eventually included in the current rulemaking package. Those differences related to the circumstances under which mitigation would be required, and thus both to the environmental impacts and the costs of ADF regulation. Growth Energy believes that CARB did not substantially comply with SB 617 in connection with the ADF rulemaking, and that the Department of Finance failed to perform a mandatory duty to notify CARB and the public of CARB's noncompliance and to require CARB to comply. Growth Energy therefore requests that the Board reopen the SB 617 process, and allow that process to proceed simultaneously with other work on the ADF regulation. If the Board believes there was substantial compliance with SB 617 in the ADF rulemaking process, Growth Energy requests that CARB explain the basis for that belief.

D. External Peer Review

The Executive Officer has indicated that he has sought external scientific peer review in connection with the LCFS rulemaking. The subjects of that peer review effort, however, are unknown, and it is not clear whether the Executive Officer has sought peer review under section 57004 of the Health & Safety Code for the scientific basis and scientific portions of any part of the currently proposed ADF regulation. If no such peer review has been sought and completed, Growth Energy requests an explanation of the reason why none was sought and completed.

V. CONCLUSION

Growth Energy appreciates the opportunity to participate in these rulemakings. Growth Energy believes that the current record does not enable the Board to adopt the regulatory proposals presented by the staff, and hopes that the Board will reconsider the staff's decision not to propose the alternative to the LCFS program that Growth Energy offered in the SB 617 process in 2014. If adopted, the current LCFS proposal will have a devastating impact on Growth Energy's members, who will be forced to exit from the California alternative fuels market. Such an outcome will likely trigger the cost-containment caps in the proposed regulation, and any claimed benefits of the LCFS program will be compromised or lost. By contrast, Growth Energy's alternative proposal will assure the continued supply of reasonably-priced renewable fuel to the California market, and can achieve the same overall GHG reductions as sought by the 2009 LCFS regulation while not creating any increases in criteria pollutants.

Respectfully submitted,

GROWTH ENERGY

February 17, 2015

Appendix A

Comments on ARB's Corn Ethanol Land Use Emissions
February 10, 2015
Air Improvement Resource, Inc.

Introduction

ARB presented a new land use emission estimate for corn ethanol in the Initial Statement of Reasons (ISOR). The derivation of this estimate was discussed in Appendix I to the ISOR. ARB developed the corn ethanol estimate from the average of 30 scenarios, where each scenario represented a unique run of the Global Trade and Analysis Project (GTAP) model. The 30-scenario average is 19.8 g CO2 e/MJ. This value is 10.2 gCO2/MJ lower than ARB's current estimate of 30 g CO2e/MJ.

ARB held 3 workshops in developing the new LUC values; one in March 2014, one in September 2014, and a final one in November 2014. AIR participated in all 3 workshops, and submitted comments to the Staff on all 3 workshops. Our previous comments are included as Attachments 1-3 to this document.

Very little changed in ARB's emissions for corn between the November 22 workshop and the ISOR. The value at the November 22 workshop was 20.0 g CO2e/MJ.

Through the workshop process, we have made a number of comments on the Staff's approach and analysis. One comment was adopted, but the remainder were either ignored or shifted to ARB's "Long Term" project list. Table 1 below summarizes the status of comments made. We have divided the recommendations into two categories – GTAP, and AEZ-EF. [1] We have included 3 categories for the status – adopted, ignored, or shifted to long-term.

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[1] GTAP determines how much and what type land is needed and where, and the AEZ-EF model determines the emissions of the various land transitions. Both models are needed to estimate LUC for a biofuel.

Table 1. Status of Recommended Items				
Category	AIR Recommendation	Adopted	Ignored	Long-Term
GTAP	Revise the model land supply structure	X		
	Drop the lower price-yield values		X	X
	Include multiple cropping effects			X
	Evaluate land intensification effects		X	X
	Include effects of conservation reserve program (CRP)			X
	Include additional effects of fertilizer, livestock, paddy rice emissions			X
	Develop and include cropland-pasture from other regions			X
AEZ-EF	Do a comparison of CCLUB to AEZ-EF		X	X

Table 1 shows that many of the items recommended have simply been shifted for future study. Most of these items were raised by both AIR and the Expert Working Group (EWG) at least 4 years ago (two examples are (1) including CRP in the analysis, and (2) including the effects of livestock and rice paddy emissions). We have listed several items as either being ignored and shifted to the future or just being ignored, because either Staff's response to our input was inadequate, or it was not addressed at all in the ISOR, or both.

For many of the items that have been shifted to further study, we have presented in comments submitted previously, information showing they could be included now (examples are land intensification effects). Some items shifted to further study legitimately require further study, for example, including cropland-pasture from other regions.

Overall, we believe the LUC value of 19.8 gCO2e/MJ for corn ethanol is still too high. The implications of overestimating the LUC value for corn ethanol are that it could lead to shuffling of fuels without any reduction in greenhouse gases and increased costs of compliance with the LCFS.

The following section discusses each of the comments above. We skip a discussion of the model structure, since that comment was adopted by the staff.

Price-Yield Values

The ARB analysis uses five price-yield values: 0.05, 0.10, 0.175, 0.25, and 0.35. The average of these 5 values is 0.19. The Purdue recommended value is 0.25, and the EWG recommended 0.25. ARB sponsored research indicating that there was little or no price-yield response (i.e., 0.0). Our comments on price yield were that ARB should drop the lower price yield values (0.05 and 0.10) because the research supporting these lower values was developed over the very short term (1-3 years of price and yield data), and the GTAP model is a longer-term model (5-10 years). [2] ARB utilizes an 11.59 billion gallon per year shock of corn ethanol in its corn ethanol modeling, clearly illustrating that ARB is exercising the model with a medium-term shock, and not a short term shock. Thus, ARB's use of short term price yield responses with the medium or longer term GTAP model is clearly inconsistent.

In the ISOR, ARB references a recent analysis by David Rocke at UC Davis in support of using lower price-yield responses. [3] The Rocke analysis utilized one set of data from a 2012 dissertation by Juan Francisco Rosas Perez. [4] The dissertation indicated that the price-yield response was in the region of 0.29, very close to the Purdue default value. Rocke obtained the data from the dissertation, conducted his own statistical analysis, and concluded that the data did not support the 0.29 price yield value.

Because of the differences between these two analyses (Perez and Rocke), which are clearly important to understand fully, AIR requested the data Rocke used for his analysis from ARB staff. While staff said they were trying to get the data for AIR, the data was never supplied by staff. Therefore, we were unable to replicate Rocke's analysis of the Perez data. There is not enough information in Rocke's write-up to reject the Perez analysis (the rebuttal is only 3 pages). In addition, this is only one of two sources (according to Rocke) that were used to support the 0.25 price-yield value, Rocke did not attempt to critique the other source. Thus, because we were not able to replicate Rocke's sketchy analysis, and Rocke only critiqued one source, ARB cannot rely on the Rocke analysis for its use of low price-yield values, and should therefore eliminate the lowest value (0.05), or the lowest two values (0.05 and 0.10).

The impacts of eliminating one or both of these values on corn ethanol LUC emissions is shown in Table 1. Without the lowest price yield value of 0.05, the LUC value for corn is 17.62. Without both 0.05 and 0.10, the LUC value is 15.53

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[2] "Discussion of the Yield Price Elasticity of GTAP", Taheripour and Tyner, Purdue University, April 2014.

[3] "Statistical issues Related to the Low-Carbon Fuel Standard", October 31, 2014.

[4] "Essays on the Environmental Effects of Agricultural Production", Dissertation, Perez, Juan Francisco Rosas, Iowa State University.

gCO2e/MJ. As before, we recommend that ARB eliminate the lowest two price-yield values.

Table 1. Impact of the Low Price-Yield Values		
Average of ARB Scenarios	Average price-yield	LUC (gCO2e/MJ)
All (ARB value)	0.19	19.84
w/o 0.05 price-yield	0.21	17.62
w/o 0.05, 0.1 price-yield	0.26	15.53

Multiple-Cropping and Land Intensification

GTAP currently does not include any double or multiple cropping. When crop prices increase, producers get more out of the same piece of land by planting second and even third crops. This is particularly true in Brazil, where corn is planted on soybeans, and even in the US, where wheat is planted and corn/soybeans are planted in the same year. This is one process of land "intensification", whereby existing cropland is used to a greater degree before conversion of non-cropland.

In our September 2014 workshop comments (Attachment 2) we pointed out that multiple cropping can be conservatively modeled by increasing the price yield value. We recommended a +0.05 increase in price yield from about the 0.25 Purdue default level to 0.30, other commenters have recommended similar and higher amounts. Ignoring multiple cropping, as ARB is currently doing (or, just deferring including it to some unknown future date) is not technically acceptable or defensible.

The empirical evidence for intensification globally was developed from data by the Babcock/Iqbal analysis, which we covered in detail in our comments on the November 22 workshop. [5] This analysis showed that over the last 10-15 years of biofuel expansion, there has been no net land conversion from forest and pasture to crops in many regions such as the US, Western Europe, and China. In our November comments (Attachment 3), we developed a filter that could be applied to the ARB results based on GTAP to estimate LUC of biofuels. We showed that application of this filter would reduce LUC from corn ethanol from 20 gCO2/MJ to a range of 6-13 g CO2e/MJ (see Table 2 in Attachment 3).

ARB has known about the inability of GTAP to account for multiple cropping since the last time land use values were adopted in 2009. It is inexcusable that ARB would still be relying on LUC values that do not include multiple cropping or more generally, some accounting for land intensification. We have provided two methods to ARB for accounting for these effects in this version of LUC estimates – either use a somewhat high price-yield factor, or use the filter we developed from the

[5] Using Recent Land Use Changes to Validate Land use Change Models", Babcock and Iqbal, Staff Report 14-SR- 109, Center for Agriculture and Rural Development, Iowa State University, www.card.iastate.edu.

Babcock/Iqbal study. These methods can be applied conservatively to avoid over-accounting for their effects. Of course, this, as well as many other issues, could also be studied further in the future. But some accounting for multiple cropping and land intensification should be included with this LCFS re-adoption.

Conservation Reserve Program

Our comments have also consistently pointed out that ARB should also include the effects of Conservation Reserve Program land (CRP) in mitigating land use emissions. The GTAP model already includes the computer code to access CRP land.[6] We have also presented direct evidence from USDA statistics that conversion of CRP back to crop has already occurred over the last five years (see Table 2 of our comments on the March 11 workshop, Attachment 1). Therefore, we are not discussing a theoretical possibility of this conversion occurring in the future with biofuel expansion. It has already happened, and ARB has ignored it.

Inclusion of US CRP land in estimating LUC of biofuels would clearly lower LUC values. The carbon stored on CRP (above and below ground) reactivated to crops would be similar to ARB's current estimate for pasture. It could even be a little higher than pasture, if shrubs and other plants had started to grow on this land. In some cases, CRP land could even include some young forest. However, it is not likely that forest CRP land would be reactivated back to crops, rather the CRP converted back to crops would be land relatively easy to convert. But the inclusion of CRP land in GTAP modeling would reduce overall the forest estimated to be converted in the US, thereby showing a reduction in GHG emissions from the case of not including CRP land in the analysis.

Include Livestock and Paddy Rice Emission Credits

These are other indirect effects that were identified at the time the last land use values were finalized by the ARB. The biofuel shocks increase crop prices, thereby reducing livestock herds and also reducing the paddy rice crop. Livestock and rice produce prodigious amounts of methane, so the reduction in these two items reduces GHG emissions from biofuels. EPA included these effects in its implementation of the Renewable Fuel Standard in 2010. Given that EPA included these effects several years ago, it is surprising that ARB postponed the inclusion of these effects in their modeling.

Include Fallow Land

[6] The AEZ-EF appendix indicates that "GTAP-BIO does not consider conversion of CRP land." This is not exactly true. The computer code for including this land is in the model, and it is easy to activate. AIR has activated this code, and GTAP, along with AEZ-EF (assuming CRP land is similar to pasture) predicts a 1-2 gCO2/MJ reduction for including CRP land in the analysis.

We showed in Table 6 of our comments on the November workshop (Attachment 3) that worldwide there are 193 million hectares of fallow land. The model currently has no capability of accessing this land for increased crop production even though it is probably the most likely land to respond to higher crop demand and is land that could be brought into production without any land use change.

Include Cropland-Pasture from other Regions

The GTAP model includes cropland-pasture for the US and Brazil. Cropland-pasture is land that is used alternatively for either cropland or pasture, depending on economics to the producer and other factors. The inclusion of the land type for these two countries reduced LUC emission predictions from GTAP significantly. The US and Brazil are not the only regions with cropland-pasture. Canada, Western Europe, and some other regions also utilize cropland-pasture.

Compare CCLUB to AEZ-EF

ARB uses its AEZ-EF model to estimate the emissions of various land transitions, for example, forest to crop, pasture to crop, crop to pasture and so on. The model was not finalized and released until late November 2014.

AIR has previously commented that ARB should also evaluate LUC emissions with the CCLUB model. [7]CCLUB is used by Argonne to estimate LUC emissions for various biofuels in the GREET model (GREET2013, GREET2014). CCLUB was available in late 2013. CCLUB basically uses the same international emissions that EPA used in the RFS, but has much more detailed emissions for the US. CCLUB is not even referenced by the AEZ-EF documentation. ARB claims to have evaluated CCLUB, but there is no indication of that in either the AEZ-EF documentation, in Appendix I, or in the ISOR. [8] Therefore, due to the fact that ARB released the final AEZ-EF model so late in the process, and that there are no references to CCLUB in any of the ARB documentation, we are not clear on what the advantages there are to AEZ-EF over CCLUB. There was little time for us to perform an in-depth analysis of the differences in these two models that estimate the emissions of various land transitions.

AIR evaluated the impact of using CCLUB instead of AEZ-EF for predicting emissions. The impacts are shown in Table 2. LUC emissions with CCLUB are less than ½ of ARB's AEZ-EF model. AEZ-EF is not superior to CCLUB, certainly the most technically defensible parts of both models should be combined.

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[7] Dunn, J., Mueller, S, Kwon, H.Y., Wander, M., Wang, M., "Carbon Calculator for Land Use Change from Biofuels Production (CCLUB)", Argonne National Laboratory, ANL/ESD/13-8, September 2013.

[8] In their list of long-term updates to LUC in the ISOR, ARB's number 2 item is to "use improved emission factors, as they become available." However, it appears ARB has not fully evaluated emission factors in CCLUB, which were available long before ARB finalized its AEZ-EF model.

Table 2. Comparison of Corn Ethanol LUC Emissions	
Scenario	LUC (g CO2e/MJ)
ARB Average Inputs with AEZ-EF Emissions	17.14
ARB Average Inputs with CCLUB Emissions	7.77

Attachment 1

Comments on ARB's March 11 Workshop on
The Low Carbon Fuel Standard
Air Improvement Resource, Inc.
April 6, 2013

These comments are primarily on the workshop presentations provided by CARB, and some of the documentation provided by CARB on the AEZ-EF model shortly after the workshop. The following comments focus on Land Use Change and Facility Registration components of the LCFS.

Land use Change Emissions

There are two models used to estimate the land use change emissions – the Agri-Economic Zone Emission Factor (AEZ-EF) model, and the Global Trade Analysis Project (GTAP). GTAP is a general equilibrium model used to determine land transitions (like pasture to cropland and forest to cropland) in similar agro-economic zones in various regions of the world. The AEZ-EF model is used in conjunction with the GTAP to determine emissions released by the land-use transitions.

We discuss the GTAP model first, followed by the AEZ-EF Model. We then use the ARB-GTAP model and a much more appropriate Purdue GTAP model to estimate the impacts of our recommendations of changes on land use change (LUC) emissions for corn ethanol.

<u>Global Trade Analysis Project (GTAP)</u>

GTAP contains global land pools of cropland, forest, pasture, Conservation Resource Program (CRP) land (in the US), and cropland pasture (in the US and Brazil). The base year for the current model is calendar year 2004. In modeling biofuel increases, the model is "shocked" with the biofuel increase (corn ethanol, for example), and since this requires a significant increase in corn production, the model converts some other cropland to corn production, converts some pasture to crop production, and converts some forest to crop production. The model also contains a price-yield elasticity, such that when the model is shocked for increased corn ethanol, crop prices increase, and yields also increase somewhat on all cropland. Thus, increased production is met through (1) cropland expansion into non-cropland (which creates land use change emissions), and (2) yield increases on existing cropland.

There are other ways in which crop production increases in addition to land expansion and yield increases. A 2013 study by Roy and Foley shows there are three other ways crop production increases: (1) using the existing standing cropland area more frequently by multiple cropping, (2) leaving less land fallow, and (3) having fewer crop failures.[9] None of these 3 ways involves a land use change, or land use change emissions. Furthermore, GTAP does not include these 3 factors: GTAP does not account for double cropping, has no fallow land inventory, and cannot model reduced crop failures. Roy and Foley point out that the influence in these 3 factors on crop production can be estimated by comparing trends in total harvested area to total cropland.

> The growth in annually harvested cropland and standing cropland has been changing in recent decades. Analyzing the 177 crops traced by FAO since 1961 shows that the amount of annually harvested land has increased much faster than the reported total standing cropland on the globe. While standing cropland has increased at the rate of 3.5 mha/year, the annually harvested land increased at a much faster rate of 5.5 mha/yr.

The difference in the above growth rates – 2.0 mha/year – is due to the 3 factors mentioned earlier, which have no land use emissions impact. The authors also examine the potential for the increase in harvested area to continue to increase faster than standing cropland in the future, and find that these trends should continue.

It is difficult to incorporate these factors into the current GTAP model, because these factors require a dynamic GTAP model, and the current model is a static model.[10] However, the analysis of these trends can be used to inform the ranges of input elasticities for the current static GTAP model used by ARB, particularly the price-yield elasticity. Increasing the price yield elasticity in GTAP increases crop production without a land use impact. Thus, the Ray/Foley study argues for a relatively high price-yield elasticity range. ARB, however, has selected a very low price yield elasticity range. This is discussed in more detail in the next section.

Review of CARB's GTAP Modeling

Price-Yield Elasticity Range

GTAP includes a price-yield elasticity of 0.25 as a default. This level is in part based on extensive research by the GTAP modeling community. [11] The Expert Working Group also recommended this value. The EWG also recommended higher values for regions with significant double cropping, since GTAP does not explicitly include double cropping. GTAP researchers have also pointed out GTAP is a medium-term model, with projections being applicable in the 5-10 year timeframe. CARB appears to concur with this timeframe for GTAP, because CARB describes the model as a

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[9] Ray, D.K., and Foley, J.A., *Increasing global harvest frequency: recent trends and future directions,* Environmental Research Letters, (2013), 044041, IOP Publishing.

[10] Purdue is continuing to develop a dynamic GTAP model for these and other reasons.

[11] Keeney and Hertel, "Yield Response to Prices: Implications for Policy Modeling", Working Paper #08-13, August 2008, Department of Agricultural Economics, Purdue University.

"Current" model, meaning, that its estimates are applicable to the 2013/2014 timeframe, even though its primary data is for 2004.[12]

CARB, however, performed sensitivity analyses using price-yield elasticity values from 0.05-0.30 (20%-120% of the default value). CARB's selection of the lower end of the range came from a variety of price-yield studies that were very short term (1-2 years) in nature, and were clearly not appropriate for the GTAP timeframe. All studies on data less than about 4 years should not even be considered in establishing the range of this parameter to use in modeling. Furthermore, CARB did not consider the analysis by Ray and Foley in determining the range of price-yield values to use.

CARB performed sensitivity analyses on several other parameters. Most of these values were in the range of 80%-120% of the GTAP default level, for example, CARB performed sensitivity modeling of the ETA parameter at the baseline (default), 80% of the baseline, and 120% of the baseline. We support performing sensitivity modeling at different price-yield levels, however, the range should be at least 80%-120% of the Purdue baseline value of 0.25, or 0.20 to 0.30. However even this range is not nearly high enough to properly reflect the increase in crop production that has occurred without land use changes reflected by Ray and Foley analysis referenced earlier.

ETL1 and ETL2 Values

CARB updated the land transformation elasticities (ETL1 and ETL2) in GTAP prior to estimating land use changes. ETL1 governs the transformations between forest, crops, and pasture, and ETL2 governs the transformations between various crops. CARB appears to have used some, but not all, ETL1 and ETL2 values from a 2013 Applied Science paper by Taheripour and Tyner. [13] In the Applied Sciences paper, Taheripour and Tyner indicate

> We tune the regional land transformation elasticities based on actual historical observations on changes in land cover and distribution of cropland among alternative crops during the past two decades. To accomplish this task we use published data on cropland use around the world by the Food and Agriculture Organization (FAO) of the United Nations over the period 1990-2010.

The differences in ETL1 and ETL2 values between the Applied Sciences paper and CARB are shown in Table 1 below.

[12] See page 57 of the CARB March 11 Workshop Briefing, iluc_presentation_handouts_031014.pdf.

[13] Taheripour and Tyner, "Biofuels and Land Use Change: Applying Recent Evidence to Model Estimates", Applied Sciences, 2013, 3, 14-38.

Table 1. Differences in ETL1 and ETL2 Values Between CARB and Purdue				
Region	Purdue – Applied Sciences 2013		CARB	
	ETL1	ETL2	ETL1	ETL2
Brazil	-0.30	-0.50	-0.20	-0.75
S_O_Amer	-0.30	-0.25	-0.10	-0.50
R_S_Asia	-0.10	-0.25	-0.10	-0.75
Russia	-0.20	-0.75	-0.02	-0.75
S_S_Afr	-0.30	-0.50	-0.30	-0.25

It is not clear why CARB chose different ETL1 and ETL2 values than Purdue, and what analysis or data CARB based these values on. An explanation of this should be provided for review, or CARB should use the ETL1 and ETL2 values that were developed by Taheripour and Tyner.

Model Nesting Structure

The Applied Science paper referenced above also included another major improvement in GTAP. According to the paper

> The GTAP-BIO model puts three types of land cover items (forest, pasture, and cropland) into one nest an implicitly assumes that the economic costs of converting one hectare of forest to cropland is similar to the economic cost of converting one hectare of pasture land to cropland and vice versa. This set up another key deficiency of the GTAP-BIO model. Including cropland, forest, and pastureland in the same nest could cause systematic bias in land conversion processes among land cover types due to biofuel production. In general this is not the case and often the opportunity costs of converting forest to cropland is higher than the economic cost of converting pastureland to cropland.

The Expert Working group studying elasticity parameters in GTAP identified this nesting structure as a key deficiency in the model and recommended using a revised nesting structure.

Taheripour and Tyner altered the land cover component of the land supply tree to have forest and pasture land in two different nests. Then they re-evaluated global land use impacts due to the USA ethanol program using the improved model tuned with actual observations. They showed that, compared to the old model

> The new model projects: (1) less expansion in global cropland, (2) lower share for the USA economy in global cropland expansion, (3) and lower forest share in global cropland expansion.

CARB did not include the model nesting structure changes implemented by Taheripour and Tyner, and recommended by the Expert Working Group, even though this revised model was available to CARB in early 2013. CARB should include this critical change in the GTAP model.

Additional Cropland/Pasture Areas in Canada and EU27

GTAP has been updated to include cropland/pasture in the US and Brazil (CARB used the model with these additions). Other regions of the world, such as Canada and the EU27 (and probably many other regions of the world) also have a significant amount of cropland/pasture and idle land. These land areas should be added to GTAP.

Conservation Resource Program Impacts

The GTAP model includes the ability to include CRP land in the land inventory for the US. There has been a significant amount of land converted to production from CRP land in the last seven years. Table 2 shows data from the Conservation Resource Program. [14] These data show over 10 million acres of CRP land have gone back into production. These are not forest acres that have gone into production. Over the period from 2007-2011, CRP acreage in wetlands and buffers increased. Clearly, GTAP should be run to access CRP land in the US prior to converting forests or even cropland/pasture.

[14] "Annual Summary And Enrollment Statistics", FY2011 for 2007-2011, and December 30 Reports for 2012 and 2013, http://www.fsa.usda.gov/FSA/webapp?area=home&subject=copr&topic=rns-css.

Table 2. CRP Land Enrolled	
Year	Area (million acres)
2007	36.8
2008	34.6
2009	33.8
2010	31.3
2011	31.1
2012	27.1
2013	25.6

<u>AEZ-EF Model</u>

Use of Carbon Data on Accessible and Inaccessible Forests to Determine Emissions from Forest Conversion

The AEZ-EF report indicates

> The carbon data used in AEZ-EF have been aggregated to GTAP-BIO boundaries, but they include both accessible and inaccessible forests, as well as grasslands other than those used for livestock grazing, and thus represent broader resources than those represented in GTAP-BIO.

It is not clear why CARB is including inaccessible forests in developing forest carbon stocks. If forests are inaccessible, then it is highly unlikely they would be converted to pasture or cropland. CARB should instead develop forest carbon from accessible or commercial forests. Detailed carbon data on public, private, and other forests is utilized by EPA in estimating its annual GHG inventories.[15] The carbon in private forests (most likely of forests to be converted to pasture/cropland) is much lower than public or other forests.

Wood Used to Produce Energy

In the new AEZ-EF model, for forest converted to cropland or pasture, CARB is now accounting for carbon stored in hardwood products (HWP). The storage rates are different for different regions, and are based on a 2012 study by Earles, Yeh, and Skog. The HWP fraction ranges between 2-36%.

In addition to accounting for carbon stored in HWP, CARB should also account for wood mass that is used for fuel during forest clearing. Wood that is burned to

[15] USDA Forest Service (2010a), Forest Inventory and Analysis National Program:User Information. U.S. Department of Agriculture Forest Service. Washington, DC. Available online at http://fia.fs.fed.us/tools-data/docs/default.asp.

produce energy (for a sawmill, for example) is replacing fossil-fueled energy, and is renewable. CARB does not count CO2 emissions from facilities that use waste wood to produce energy for fuel production (CARB does, however, count non-CO2 GHG emissions, which is appropriate). Heath et al estimate that 35% of carbon from forest clearing is used for energy.[16] In the US, Canada, and the EU27, CARB should not count the CO2 from wood used to produce energy.

CCLUB Model

CARB should consider using the Carbon Calculator for Land Use Change from Biofuels Production (CCLUB) model for estimating emissions.[17] Like AEZ-EF, the model was designed to be integrated with GTAP. It has several advantages over AEZ-EF. First, instead of using the Harmonized World Database (HWD) for soil, it uses the CENTURY model, which contains much more specific information on soil carbon for the US than the HWD, on a county-by-county basis. Second, it uses county-by-county carbon data from forest ecosystems for the US from the Carbon Online Estimator (COLE) database, developed by Van Deusen and Heath in 2010 and 2013. [18,19] Third, it allows the user to input HWP fractions, and fourth, it does not count CO2 from the forest wood used to produce energy. For areas outside of the US, it utilizes Winrock emissions.

CARB has conducted uncertainty analysis of its land use estimates using only AEZ-EF and GTAP. Using the CCLUB model with GTAP to estimate land use change emissions would also provide more information on the uncertainty of CARB's estimates.

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[16] L. Heath, R. Birdsey, C. Row, and A. Plantinga. "1996 carbon pools and flux in U.S. forest products", Forest Ecosystems, Forest Management, and the Global Carbon Cycle, M. Apps and D. Price, eds. NATO ASI Series I:Global Environment Changes, Volume 40, Springer-Verlag, ppg 271-278.

[17] See reference 7.

[18] Van Duesen, P., and Heath, L., 2010. Weighted Analysis Methods for Mapped Plot Forest Inventory Data: Tables, regressions, maps and graphs. Forest Ecol. Manage. 260:1607-1612.

[19] Van Duesen, P. and Heath, L. 2013. COLE web applications suite. NCASI and USDA Forest Service, Northern Research Station. Available at http://www.ncasi2.org/COLE/

Updated LUC Modeling

AIR downloaded ARB's GTAP model and the AEZ-EF model to determine the impacts of some of our suggestions. ARB did not supply example run results for any particular biofuel shock. ARB ran the models under 1440 different input conditions, for 5 different biofuel shocks, and determined the average emissions for each of the 1440 runs (a total of 7200 runs). The results are shown in Table 3.

Table 3. ARB Land Use Results, March 11 Workshop	
Biofuel	LUC Emissions (gCO2e/MJ)
Corn Ethanol	23.2
Sugarcane Ethanol	26.5
Soy Biodiesel	30.2
Canola Biodiesel	41.6
Sorghum Ethanol	17.5

In this analysis we test the impact of three factors that should be changed in the ARB modeling:

- ARB's ETL1 and ETL2 values
- Model Nesting Structure
- Price-Yield Range

It is clearly impractical for us to run the model 1440 times to test the impact of these 3 items. However, it is possible to test the impact with a representative model run. To create the representative model run, we first estimated the average of the ARB inputs. Next, we ran the model with a corn ethanol shock to determine the LUC emissions. Finally, we changed the price yield elasticity, until the model run gave the same answer as corn ethanol in Table 3. The average model inputs are shown in Table 4.

Table 4. Average ARB GTAP Inputs	
Input Parameter	Average Value
Price Yield (Ydel)	0.175
PAEL, US	0.3250
PAEL, Brazil	0.1875
ETA	ARB Baseline
ETL1, ETL2	ARB Baseline

When we ran the case in Table 4, we obtained corn ethanol emissions of 21.66 gCO2e/MJ. We then reduced the price yield elasticity from 0.175 to 0.1507, and obtained emissions of 23.22 gCO2e/MJ, which is the same as ARB's corn ethanol estimate. This is our single run that generally represents CARB's 1440 cases.

The impact of the 3 changes on LUC emissions for the corn ethanol shock are shown in Table 5.

Table 5. Impacts of Changes in GTAP Modeling	
Scenario	LUC Emissions (gCO2e/MJ)
AIR "Representative" Case	23.22
Change ETL1 and ETL2 parameters to Purdue "tuned" values	21.20
Implement Purdue GTAP Nesting Structure	19.00
Use Purdue Default Price-Yield Range	14.63
Include CRP Land Conversions	13.75

Table 5 shows likely emissions of 13.75 g CO2e/MJ instead of 23.22 gCO2e/MJ if these changes are implemented and the various runs are repeated. The emissions would be even lower if the model were modified to more properly reflect (1) the Ray and Foley analysis that a major part of crop production has increased without a land use change, and (2) the ARB analysis properly accounted for wood from forest that is used for fuel and replaces fossil fuel during forest clearing.

2.0 Fuel Pathways and Producer Facility Registration

Growth Energy supports the streamlining of the application process for biofuel production facilities, however, Growth Energy does not support limiting the pathways a facility can apply for, nor does Growth Energy support implementation of CI "bins" that facilities must use when registering the facilities. These changes would both severely limit continued innovation in biofuel facilities.

At the workshop, CARB envisioned bins of either 5, 7, or 9 CI values, with all facilities falling in a bin range getting the same, midpoint value of the bin. For a 7 CI bin case, for example, facilities falling in a bin from 61-67 would all be assigned a value of 64, whether their CI is 61.1 or 66.9. Furthermore, a facility with an actual CI of 65 (assigned value of 64) would not be able to obtain a lower CI value unless it reduced its actual CI to the upper part of the next bin range, or 60.9 (a difference of 4.1 CI). A facility at 61.1, however, with an assigned value of 64 would be able to get into the next lowest bin by reducing its CI to the same value of 60.9, a difference of only 0.2 CI. Clearly, if we are understanding CARB's bin approach correctly, it appears to have significant problems, no matter how the bins are designed.

A second major concern we have with the bin approach is that it is not at all consistent with what ARB is proposing for refineries producing gasoline and diesel. CARB's GHG Emission Reductions for Refineries proposal indicates that CARB is willing to provide credit under the LCFS regulations to refineries, with no minimum CI reduction required. In other words, a refinery that has a project to reduce its CI by 0.1 CI would receive consideration. But under the binning approach for biorefineries above, there is a much higher minimum threshold for consideration of a lower bin. Thus, gasoline/diesel refineries receive special treatment that biofuel facilities do not.

Attachment 2

Comments on ARB's September 29th Workshop
On Land Use Change Emissions
Air Improvement Resource, Inc.
October 17, 2014

Introduction

On September 29, 2014 ARB held a workshop on land use change emissions. ARB presented new information on their analysis of LUC emissions for corn ethanol, soybean biodiesel, canola biodiesel, cane ethanol and sorghum ethanol.

We have reviewed the information CARB presented at the workshop and thereafter, and also have obtained the new GTAP model and performed some additional modeling runs. We appreciate the additional time that the staff has provided for us to provide these comments. We will have additional comments later. The comments are presented here are organized into the following sections:

- Irrigated/Rain-Fed Cropland Category
- Land Supply Structure
- ETL11, ETL12, ETL4 and ETL5
- ARB's 30-Scenario Average
- Yield-Price Elasticity
- Cropland Pasture Elasticity
- Corn Ethanol LUC Impacts of our Recommendations

Please add these comments to the page on ARB's website that has been previously established for workshop comments.

Irrigated/Rain-fed Cropland Category

Earlier versions of the GTAP model used an average of irrigated and rain-fed cropland. The expansion of cropland in the model did not differentiate between irrigated or rain-fed areas. Irrigated cropland typically has a higher yield compared to rained cropland in a given Region and AEZ. If cropland expansion occurs on irrigated land, higher yields translate into smaller land requirements. But availability of water for irrigation may limit expansion into irrigated land.

The new version of GTAP developed by Purdue for ARB includes an option to differentiate between irrigated and rainfed cropland. The availability of irrigated land for cropland expansion then can be constrained in certain regions and AEZs, if there is sufficient evidence to constrain expansion of irrigated lands.

ARB used analyses and data from the World Resources Institute (WRI) to determine which regions and AEZs within these regions to constrain expansion into irrigated land.

Figure 1 shows the Regions and AEZs where irrigated land is constrained for the ARB LUC analyses. These regions and AEZs were determined from the WRI reports. [20][21]

Figure 1

GTAP: Water Constrained Regions/AEZs

AEZ → / Region ↓	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
1 USA							1	1	1				1	1				
2 EU27									1									
3 BRAZIL																		
4 CAN							1	1										
5 JAPAN									1			1						
6 CHIHKG							1	1	1	1			1					
7 INDIA	1	1	1				1	1	1	1					1	1		
8 C_C_Amer	1	1					1	1	1	1	1							
9 S_o_Amer	1	1					1	1	1									
10 E_Asia											1							
11 Mala_Indo				1	1													
12 R_SE_Asia																		
13 R_S_Asia	1		1				1	1	1	1			1					
14 Russia																		
15 Oth_CEE_CIS							1	1					1	1				
16 Oth_Europe																		
17 MEAS_NAfr			1	1			1	1	1	1								
18 S_S_AFR								1										
19 Oceania	1							1	1	1	1							

1 indicates water constrained

We reviewed the WRI reports, but were unable to determine how ARB used the information in these reports to identify the regions and AEZs that should have irrigated land constrained. Because we have been unable to locate the technical documentation that would explain how ARB used the WRI reports to draw the conclusions shown in Figure 1, we request that the staff provide the public with that documentation, and then allow at least five business days for comment.

ARB presented little information at the workshop to evaluate the size of this impact on land use emissions. To evaluate the impact of constraining expansion on irrigated land, AIR ran GTAP with and without the irrigation constraint for corn ethanol, using Purdue and ARB's average elasticity inputs. The results are shown in Table 1.

[20] *Aqueduct Global Maps 2.1: Constructing Decision-Relevant Global Water Risk Indictors*, WRI, April 2014.

[21] *A Weighted Aggregation of Spatially Distinct Hyrdrological Indicators*, WRI, December 2013.

Table 1. LUC Impact of Constraining Crop Expansion on Irrigated Land in Some Areas: Corn Ethanol					
Scenario	Ydel	PAEL	ETA	Irrigation Constrained?	LUC (gCO2e/MJ)
Purdue Best Estimates	0.25	0.4/0.2	Baseline	No	14.23
				Yes	13.32
ARB Average	0.19	0.3/0.15	Baseline	No	17.22
				Yes	16.09

For corn ethanol, constraining expansion on irrigated land adds 0.89 g/MJ for the Purdue default case, and by 1.13 g/MJ for the ARB average. ARB must document how the WRI data was used to develop areas on which cropland cannot be expanded, before including this effect for the various biofuel feedstocks.

Land Supply Structure

The land supply structure in GTAP was revised in 2013 to include four nesting structures instead of two.[22] Prior to 2013, one nest included the substitution of different types of land – forestland, cropland, and pastureland – and a second nest under cropland that included different types of crops. One elasticity – ETL1 – governed the substitution between forestland, cropland, and pastureland, and a second elasticity – ETL2 – governed the substitution between crop types. A significant concern of ARB's Expert Working Group (EWG) was that forestland, cropland, and pastureland were all in the same nest with one elasticity, which meant that forestland is as readily converted to cropland (and vice versa) as pastureland. Clearly this is not the case – the economics of converting forest to crops must be much different than converting pasture to crops.

In 2013, the land supply structure was modified by Purdue such that the first nest includes only forestland and a second category called cropland+pasture. The second nest under cropland+pasture was divided into cropland and pastureland. The third nest under cropland was divided into irrigated and rain-fed. Finally, both irrigated and rain-fed cropland was divided into different crops. The following new elasticities were defined:

- ETL11: substitution at the first level between forest and cropland+pasture
- ETL12: substitution at the second level between cropland and pasture
- ETL2: substitution between irrigated and rain-fed
- ETL4: substitution between crops under irrigated land
- ETL5: substitution between crops under rain-fed land

The new land supply structure allows the use of more disaggregated elasticities of transformation between land types.

ARB modeled two approaches in estimating land use emissions – Approach A, which assumes ETL11=ETL12, and Approach B, which provides separate estimates for ETL11

[22] See reference 13.

and ETL12. Approach A is essentially the GTAP model prior to the land supply improvements (i.e., only 1 elasticity which governs conversion of forest, crop, and pasture), while Approach B is the GTAP model with the improvements (expanded nesting supply structure). Elasticity values for Approaches A and B are shown in Attachment 1. In both approaches, the ETL2 values are identical; it is only the ETL11 and ETL12 values that are different between the approaches.

ARB did not implement Approach B in its materials presented at the March 11, 2014 workshop, in spite of the fact that GTAP was updated for land supply structure more than a year ago in January 2013. One of Growth Energy's primary comments on the materials ARB supplied at the March 11 workshop was that ARB should utilize a GTAP model with the updated land supply structure with different elasticities of conversion for forest and pasture. (i.e., Approach B). Approach A must be recognized as unrealistic, and not appropriate for use in the new regulation to set the indirect emissions factor for land use change attributed to biofuel expansion. Approach A is *not* an equally technically appropriate alternative to Approach B. Purdue no longer utilizes Approach A – it is simply now an approach that tries to mimic the old GTAP model prior to the significant improvements made in early 2013.

<u>ETL11, ETL12, ET4, ETL5</u>

ARB's ETL11, ETL12, ETL4, and ETL5 values for Approach B were presented in Slide 24 of the September 29 presentation. Based on the information that is currently available, we believe those values are more appropriate than some alternatives.

<u>ARB's 30-Scenario Average LUC Emissions</u>

In the March 11 workshop, ARB modeled 1440 separate scenarios for each biofuel, and averaged the results of these scenarios to estimate LUC for each biofuels. In the September 29 workshop, Staff had reduced this to 30 separate GTAP runs, varying 3 separate input elasticities: the yield price elasticity (YPE, or Ydel), the cropland pasture elasticity (PAEL) for the US and Brazil, and the elasticity of crop yields with respect to area expansion (ETA). There are five values for Ydel, 2 for PAEL, and 3 for ETA (5*3*2 = 30).

Growth Energy has commented previously that the number of runs should be reduced (and they have), and further support doing GTAP runs at varying elasticities, since these can affect the results. (See Attachment 2.) However, we believe that ARB has selected the wrong range of values to use for two of the input elasticities.

It is worth noting that Purdue has "best estimates" for each of these inputs. The ARB input values and Purdue best estimates are shown in Table 2.

Table 2. ARB Input Elasticities Compared to Purdue Best Estimates				
Parameter	Description	ARB Values	ARB Average Value	Purdue Best Estimate
YPE	Yield Price Elasticity	0.05, 0.125, 0.175, 0.25, 0.35	0.19	0.25
PAEL	Cropland pasture elasticity*	0.2/0.1, 0.4/0.2	0.3/0.15	0.4/0.2
ETA**	Elasticity of crop yields with respect to area expansion	Baseline, 80% of baseline, 120% of baseline	Baseline	Baseline

*The first value is for the US, the second for Brazil
** ETA varies by region. The baseline values used by ARB are the same as used by Purdue

For YPE, the ARB range is from 0.05 to 0.35, with an average value of 0.19. The range in the March 11 workshop was from 0.05 to 0.30, so ARB has increased the upper end of this range by 0.05. The average value is lower than the Purdue best estimate of 0.25, and lower values yield to higher land use emissions. For PAEL, ARB selected the ARB best estimate and an estimate one-half of that. The average of the two ETA values for Brazil and the US is lower than the Purdue best estimate. Again, lower values lead to higher land use emissions. Finally for ETA, ARB selected the Purdue best estimate as the central value, and values higher and low than the best estimate. The average of the three is at the Purdue best estimate.

For PAEL, ARB seems to have followed the methodology of selecting values higher than and lower than the Purdue best estimate. This approach makes sense to us. However, for YPE and ETA, ARB selected values rather arbitrarily that yield an average value that is significantly different than the Purdue best estimate. ARB has not presented reasons or a rationale why it did this, so it appears they did this for the sole purpose of increasing the land use emissions of crop-based biofuels. We therefore ask that ARB explain those reasons to the public and allow at least five business days for comment. Because ARB must use the best available scientific information when writing its greenhouse gas regulations, we believe that ARB needs to explain why, if it maintains the current approach, it believes that its approach is scientifically superior and uses the best available scientific data.

We present the impacts of this arbitrary decision making process later in these comments.

<u>Yield Price Elasticity (YPE, also Ydel)</u>

In our comments on the previous workshop, we indicated that GTAP is a medium term model, and that YPE values developed over the very short term were not appropriate -- as previously noted, ARB is required to use the best available scientific information under the 2006 law that applies here. The values below 0.15 referenced by ARB were short-term values, therefore, ARB should not be using values below 0.15 (i.e., 0.05 and 0.125), as they are not consistent with GTAP's general timeframe.

In addition, in our previous comments we presented information showing that Purdue's best estimate value of 0.25 does not include double-cropping, conversion of fallow land to cropland in the US, Canada and the EU27 regions, and conversion of Conservation Reserve Program (CRP) land in the United States.[23] We presented significant, substantial and compelling evidence on the conversion of fallow land and CRP land in those comments. CRP land is in the GTAP land supplies and could be utilized directly. We pointed out that both double cropping and fallow land conversion could be simulated with higher Ydel values (i.e., values above 0.25).

As indicated in the previous section, ARB used two values below 0.15 – 0.05 and 0.15. We believe these should be dropped from the Ydel analysis since they are not consistent with GTAP. Second, we believe ARB should expand the upper limit of Ydel to 0.50. The values we are recommending are 0.15, 0.2, 0.25 (Purdue best estimate), 0.3, and 0.5. The average of these values is 0.28, which is only 0.03 above the Purdue best estimate, and a reasonable conservative average to reflect a small amount of double cropping and/or fallow land conversion. If the staff does not agree, we ask that it explain why in a manner that we and other interested parties can address in a timely manner, and that the staff can consider before it proposes the new regulation.

Cropland Pasture Elasticity (PAEL)

ARB used the Purdue best estimate (0.4/0.2) and one-half of the best estimate (0.2/0.1). There is no information given on why ARB used one-half of the Purdue best estimate without also using something above the Purdue best estimate, for example, 0.6/0.3. The purpose of sensitivity analysis is determine how the model inputs affect the results. Using a sensitivity analysis on only the "low" side of the Purdue best estimate skews the land use values higher, and is not consistent with scientific norms or the requirement to use the best available scientific information. We recommend running three PAEL values, where one is the Purdue best estimate and the other two are higher and lower than the Purdue best estimate. If the staff does not agree with that recommendation, we ask that it fully explain why it is not doing so, in time for the public to comment

Corn Ethanol LUC Impacts of our Recommendations for Elasticity Inputs

The time allowed by the staff to prepare these comments did not permit us to run all of CARB's 30 cases to establish a baseline, but instead, we ran the average of the elasticity inputs, and the high and low. Results are shown in Table 3 compared to ARB's results of

[23] Double cropping refers to the practice of growing two crops on the same land in the same season. For example, often corn or soybeans are grown after winter wheat on the same land in the US. In Brazil, because the growing season is longer, often corn is grown after soybeans. The Conservation Reserve Program is a cost-share and rental payment program under the United States Department of Agriculture (USDA), and is administered by the USDA Farm Service Agency (FSA). The CRP encourages farmers to convert erodible cropland or other environmentally sensitive acreage to vegetative cover.

the 30 runs. As shown in Table 3, values generated by us are lower than ARB's values. The reasons for this are not clear. Our program files have been provided to the staff for these cases for review. For now, we have also constrained expansion on irrigated land, even though we have not had a chance to review the method ARB used to incorporate data and information from the two WRI reports.

Table 3. ARB Average, Low and High LUC Emissions for Corn Ethanol (Approach B with Irrigation Constrained)

Case	Ydel	PAEL	ETA	AIR LUC gCO2e/MJ	ARB LUC gCO2e/MJ
Average of ARB Inputs	0.19	0.3/0.15	Baseline	17.22	21.6
ARB "High"	0.05	0.2/0.1	80% of Baseline	34.49	37.0
ARB "Low"	0.35	0.4/0.2	120% of Baseline	9.68	11.5

Basically, we are recommending that ARB use the Purdue best estimates for elasticity inputs, except for Ydel, which we believe should average about 0.28 or so to reflect some double-cropping which typically takes place in Brazil and also in the US and other areas, and also conversion of some fallow land in the US, Canada, and the EU27, at a minimum. We have estimated emissions by utilizing average input parameters, instead of making 45 runs; but acknowledge that it would be more precise to perform the 45 runs and determine average emissions, since some of the effects are likely not to be linear.[24] Results are shown in Table 4.

Table 4. ARB Average and Recommended Values for Corn Ethanol (Approach B with Irrigation Constrained)

Case	Ydel	PAEL	ETA	LUC (gCO2e/MJ)
Average of ARB Inputs	0.19	0.3/0.15	Baseline	17.22
Purdue Best Estimate	0.25	0.4/0.2	Baseline	14.23
AIR Recommended*	0.28	0.4/0.2	Baseline	13.23

* We recommend performing the 45 runs and determining the average emissions, which may differ from 13.23 g/MJ.

The LUC with the Purdue best estimate inputs is 14.23 gCO2e/MJ. Our recommendation results in LUC emissions of 13.23 gCO2e/MJ, based on these inputs. Here again, we would like to know if the staff agrees with this recommendation, and, if not, we request an explanation why it does not agree in time for us to provide further input, that the staff can consider as it develops the new regulatory proposal.

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[24] 45 = 5 Ydel values (0.15, 0.2, 0.25, 0.3, 0.5), 3 PAEL values (0.2/0.1, 0.4/0.2, 0.6/0.3), and 3 ETA values (baseline, 80%, 120%).

Attachment 3

Comments on November 20 ARB iLUC Workshop
Air Improvement Resource, Inc.
December 4, 2014

Introduction

On November 20 ARB held a third workshop on indirect land use (iLUC) emissions of various biofuels. New land use emission values were presented by the Staff. A summary of the emissions for corn ethanol from the different workshops is shown in Table 1. The emissions of corn ethanol dropped slightly from 21.6 g/MJ to 20 g/MJ.

Table 1. Corn Ethanol iLUC Values (gCO2e/MJ)

Biofuel	Current Regulation	March 2014	September 2014, Approach B	November 2014, Approach B
Corn Ethanol	30.0	23.2	21.6	20.0

Very little new information was presented at this workshop. One decision that ARB made was to use GTAP "Approach B" in estimating land use emissions. Putting to the side numerous other issues related to the iLUC analysis being undertaken by the Staff and stakeholders, the use of "Approach B" is an improvement worthy of support, because it makes the GTAP model ARB is using consistent with the GTAP model developed by Purdue that is described in detail in the January 2013 Applied Science report by Purdue.[25] This approach uses separate elasticities of transformation of Forest-to-Crops and Pasture-to-Crops.

ARB made some changes in the AEZ-EF model, but as of November 30 has not released the AEZ-EF model for review and comment. As a consequence, we cannot comment on this model until it is provided for review. In order to permit effective participation in the rulemaking, ARB should make the model fully available without further delay. Waiting until the 45-day process is not appropriate given the complexity and importance of the issues that the AEZ-EF model is supposed to address.

ARB's price-yield elasticity range stayed the same as the previous workshop. According to ARB, this decision was based on a study by UC Davis. However, the UC Davis study was also not made available, so it is impossible to comment on that decision. ARB should provide public access to the relevant study and supporting materials without further delay. Consequently, our comments on price-yield remain the same as they before, i.e., that ARB should disregard th`e two lowest price-yield

[25] See reference 13.

elasticities it is currently using, and use somewhat higher price-yield elasticities, so that the average price-yield elasticity is around 0.28 or 0.30, in order to reflect multiple cropping in some countries. Our previous comments on the September 29 workshop that discuss price-yield in more detail are included as Attachment 1 to this document.

This document summarizes our further comments on the workshop and ARB's current land use estimates. It is important to note at the outset that shortly before the workshop, a significant report on using recent land use change data to validate land use change models was released by Iowa State University.[26] The study has important implications for ARB's current land use emission estimates, and thus, important implications for the overall lifecycle emissions of various biofuels as compared to petroleum-derived fuels. In response to a question from a workshop participant, ARB indicated that they had a copy of this study and were reviewing it. We believe that the Staff should address the new study in the ISOR and provide it to the peer reviewers who will be engaged to examine iLUC issues. The ISU report's findings must be used by ARB in conjunction with ARB's GTAP modeling to derive new and updated land use emission estimates for the various biofuels prior to proposing re-adoption of the Low Carbon Fuel Standard (LCFS). Failure to do this would mean that ARB would not be using the latest and best available scientific and economic information to develop its lifecycle emissions for biofuels, which we understand to be required by the governing statute, A.B 32.

Our comments are organized in the following sections:

- Summary of the Babcock/Iqbal study
- Impacts on ARB's iLUC estimates for corn ethanol
- Other Comments

<u>Summary of Babcock/Iqbal Study</u>

The study developed new methods of using existing land cover data to evaluate the extent of land transitions in the time period between 2004-2006 and 2012-2014, the time period of fairly rapid expansion of biofuel in the US. These were compared to both the FAPRI and GTAP model estimates. In short, the paper concludes that the models used by EPA and ARB significantly overestimate pasture and forest conversions to crops in many parts of the world (including the US), because they do not include land "intensification", which includes increased double-cropping, reduced fallow land, and reduced land that is planted but not harvested (in other words, increasing the harvested to planted ratio). The authors purposely did not consider crop yield improvements, which is another form of intensification and, which if also included, would further reduce iLUC GHG estimates. [27]

[26] See reference 5.

[27] Land "extensification" means conversion of forest and pasture to cropland, whereas "intensification means making existing land (cropland and idle or fallow land) more productive.

The paper first summarizes annual inflation-adjusted price changes in a number of crops from 1965 to 2012, and shows that prices of a number of key crops increased for a number of years from 2004-2012. The paper cites another study by Babcock and others that opines that about one-third of the corn price increase during this time period was due to the biofuel mandate (RFS), other factors such as crop shortfalls and other sources of increased demand account for the rest of the price increase. The reason for showing these price trends was that "the magnitude of these real price increases after such a prolonged and sustained period of flat or falling prices presents a unique opportunity to quantify how world agriculture responds to incentives to produce more." The paper goes on to state that "because indirect land use is a response to higher market prices, model predictions of land use change should be similar whether the higher prices came from increased biofuel production, increased world demand for beef, or from drought that decreased supply. This implies that the pattern of actual land use changes that we have seen since the mid-2000s should be useful to determine the reliability and accuracy of model that have been used to measure indirect land use."

The study then examines changes in "harvested land" between the two periods. The source of this information is the Statistics Division of the Food and Agriculture Organization of the United Nations (FAOSTAT).[28] These data have been widely used to measure the impact of biofuel production on expansion of land used in agriculture and to calibrate the land cover change parameter in the GTAP model used by ARB. [29,30] But the study points out that harvested land is not equal to planted land, and that harvested land will deviate from planted land "when a portion of planted land is not harvested, and when a portion of land is double or triple- cropped." The study examines data from specific countries, and shows that existing land intensification has accounted for 76% of the increase in production in Brazil, and nearly all of the increase in production in India and China.

An alternative measure of land use is developed, which is the change in FAO's arable land plus permanent crops. Figure 8, which plots the changes in this metric from 2004-2006 to 2012-2014 from the report, is shown below. The report states: "The countries in Figure 8 that either had negligible or negative extensive land use changes should be presumed to not have converted pasture or forest to crops in response to biofuel-induced higher prices. Rather, the presumption should be that any predicted change in land used in agriculture came from cropland that did not go out of production." The regions in Figure 8 with negligible or negative extensive land use changes are: Rest of Asia, the European Union, Canada, Russia, Oceania, China, South Africa, India, Central and Caribbean America, Bangladesh, Japan, Rest

[28] http://faostat3.fao.org/home/E

[29] Roberts and Schlenker, "Identifying Supply and Demand Elasticities of Agriculture Commodities: Implications for the US Ethanol Mandate", American Economic Review 103(6): 2265-95

[30] See footnote 1.

of East Asia, Other Europe and Remainder of Former Soviet Union, Ukraine, and the US.

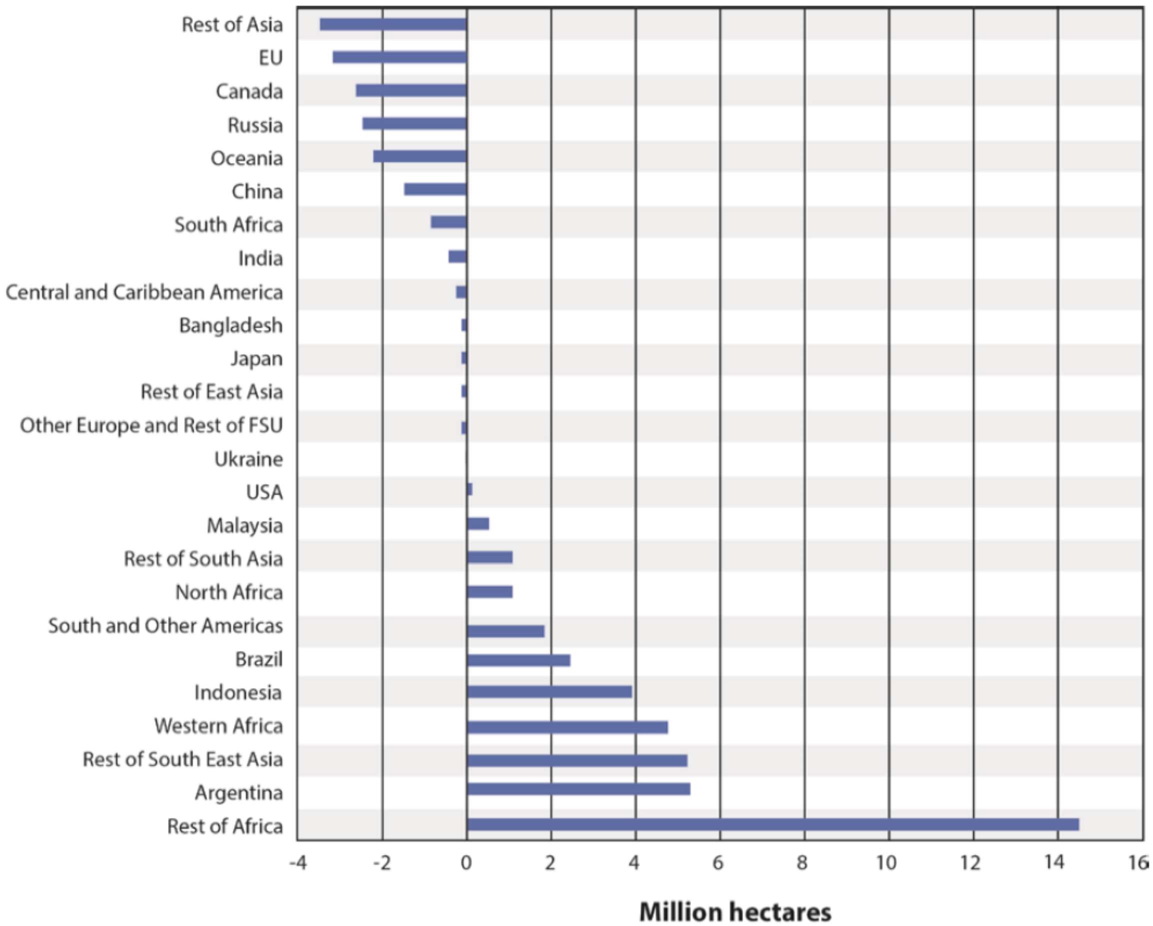

Figure 8. Change in Arable Land Plus Permanent Crops: 2004–2006 to 2010–2012

Figure 8 does show that Western Africa, and the "Rest of Africa", have significant extensive changes in arable land plus permanent crops (see Attachment 2 for countries included in the Africa regions of Figure 8). However, the study indicates that "the extent to which extensive expansion in African countries was caused by high world prices is small for the simple reason that higher world prices were not transmitted to growers in many African countries. Babcock and Iqbal cite a number of studies to support this conclusion.

Impacts of Babcock/Iqbal Study on ARB's ILUC Estimates for Corn Ethanol

As indicated earlier, we do not have ARB's most recent AEZ-EF model so we cannot replicate ARB's 20 g/MJ value for corn ethanol (the 20 g/MJ value is an average based on 30 individual runs of the GTAP model, coupled with the AEZ-EF model). We can, however, use GTAP runs with the ARB GTAP model and AEZ-EF model ARB released as a part of the September 29th workshop to develop an estimate of the impact of Babcock/Iqbal's recommendations.

The primary conclusion from the Babcock/Iqbal study is that there are regions/countries of the world that had negative or negligible extensive land use changes between 2004-2006 and 2012-2014, and these countries and regions should be presumed not to have any forest or pasture conversion to cropland in response to biofuel expansion. The countries and regions in this category were listed earlier. Other countries not on this list can still be presumed to have some extensive land use conversions (i.e., conversion of forest and pasture to crops). Thus, the Babcock/Iqbal study can be used as a filter on the existing GTAP results.

Table 2 shows our GTAP modeling from our comments on the September 29 workshop (found in Table 4 of that report). We show the iLUC for 3 cases:

- Average of ARB inputs
- Purdue best estimate
- AIR recommended inputs

Table 2. ARB Average and Recommended Values (Approach B with Irrigation Constrained) for Corn Ethanol

Case	Ydel	PAEL	ETA	AIR Estimated LUC gCO2e/MJ
Average of ARB Inputs	0.19	0.3/0.15	Baseline	17.22
Purdue Best Estimate	0.25	0.4/0.2	Baseline	14.23
AIR Recommended*	0.28	0.4/0.2	Baseline	13.23

The case with the "Average of ARB Inputs" is 17.22 gCO2e/MJ. This is less than ARB obtained with its average of the 30 scenario runs (21.6 gCO2e/MJ), but nonetheless, we can use this case to estimate the impacts of applying the country/region filter from the Babcock/Iqbal analysis.

Table 3 shows emissions from land transitions for the ARB average case. As shown in the table, Forest-to Crop transitions comprise 60% of emissions, and Pasture-to-Crop transitions comprise 21% of emissions.

Table 3. Land Transition Emissions for the ARB Average Case	
Land Transition	ARB Average, Megagrams CO2e
Forest-to-Crop	305,579,609
Pasture-to-Crop	109,196,645
Cropland-pasture to Crop	114,309,541
Crop-to-Forest	0
Crop-to-Pasture	0
Crop-to-Cropland pasture	0
Pasture-to-Forest	-20,801,279
Forest-to-Pasture	124,717
Total	508,409,234

The breakdown of Forest-to-Crop and Pasture-to-Crop emissions by GTAP region for the ARB average case are shown in Table 4. We have not shown areas with less than 1% contribution. We also have bolded the regions that Babcock/Iqbal indicate would not have Forest-to-Cropland or Pasture-to-Cropland transitions. (Our mapping of the Babcock/Iqbal regions which come from FAOSTAT, to the GTAP regions is shown in Attachment 3.)

We have shaded the sub-Sahara region[31] for several reasons – (1) GTAP predicts it is the largest contributor to emissions for the corn-ethanol expansion, (2) the Babcock/Iqbal analysis shows that the country of South Africa, part of sub-Sahara Africa, should not have forest to crop and pasture to crop transitions, and (3) we are not sure how to separate South Africa from the sub-Sahara region in GTAP, and (4) the Babcock/Iqbal report also indicates that the expansion of cropland from forest and pasture in many African countries is not price-induced.

Thus, on one hand, Babcock/Iqbal are making the case that the extensive land changes in Africa are not price driven, and therefore, not related to biofuel expansion, and so in one case the sub-Saharan region can be omitted from the corn ethanol emissions analysis. On the other hand, if these countries are included in the emissions analysis because they do have extensive land use changes, the emissions will be over-predicted because of our current inability to remove South Africa from the sub-Saharan region. Nonetheless, we will estimate iLUC emissions for these two cases – one without sub-Sahara Africa, and one with.

[31] The sub-Sahara region in GTAP includes Botswana, South Africa, Rest of South African Customs Union, Malawi, Mozambique, Tanzania, Zambia, Zimbabwe, Rest of South African Development Community, Madagascar, Uganda, and rest of sub-Saharan Africa.

Table 4. Regional Forest-Crop Plus Pasture-Crop Transition Emissions for ARB Average		
Region	Megagrams	Percent of Total Forest-to-Crop and Pasture-to-Crop Emissions
USA	**43,316,687**	**10%**
EU27	**15,681,094**	**4%**
Brazil	56,258,521	14%
Canada	**14,911,705**	**4%**
Japan	**3,745,849**	**1%**
China + Hong Kong	**16,121,420**	**4%**
India	**7,732,753**	**2%**
South America (w/o Brazil)	14,930,904	4%
Rest of Southeast Asia	13,248,332	3%
Rest of South Asia	5,810,952	1%
Other CEE_CIS	**7,867,793**	**2%**
Mideast North Africa	**2,629,014**	**1%**
Sub-Sahara Africa	**204,901,423**	**49%**
Oceania	2,628,749	1%

The results of our analysis of iLUC emissions for the ARB average case, with and without sub-Sahara Africa being included with the other areas without Forest-to-Crop and Pasture-to-Crop transitions, is shown in Table 5. Application of the Babcock/Iqbal analysis reduces iLUC emissions between 21% and 65%, depending on the treatment of emissions in sub-Sahara Africa. The range for corn ethanol for the Purdue Best Estimate (input elasticities) is between 5 and 11 g CO2e/MJ, far lower than ARB's current 20 g CO2e/MJ estimate.

Table 5. Impacts of the Babcock/Iqbal Filter on GTAP Results (g/CO2e/MJ)		
Scenario	ARB Average	Purdue Best Estimate
No Filter (from Table 2)	17.2	14.2
Filter without sub-Sahara impacts	13.3 (-21%)	10.9 (-22%)
Filter with sub-Sahara impacts	6.1 (-64%)	5.0 (-65%)

ARB should revise its iLUC emissions for various biofuels to account for the Babcock/Iqbal analysis. The reasons why emissions are lower with application of their analysis are not new – they are related to multiple cropping in certain regions, the use of idle or fallow land, and the improvement in harvested versus planted land, which are all related to higher prices for commodities. None of these items is currently included in the GTAP model that ARB is using.

Other Comments on the Workshop

Price-Yield Elasticity

As indicated earlier, ARB has stated its intent to use its current price elasticity range, with an average elasticity of 0.19. The Purdue estimate is 0.25, and it does not account for double-cropping or other intensification measures used by the agriculture industry. We have been recommending a price-yield elasticity range of 0.2-0.5, with an average of 0.28, slightly higher than the Purdue best estimate, to account for some multiple cropping. After reviewing the Babcock/Iqbal analysis, we think the best way to account for multiple cropping in the short term is by applying the Babcock/Iqbal filter. Therefore, if ARB were to utilize the Babcock/Iqbal filter on its results, the price-yield range should be modified to have an average of 0.25 at the Purdue best estimate. We do not support ARB's current range, because the lower end of the range is based on very short-term price-yield studies, and GTAP is a medium to long-term model.

Conservation Reserve Program Land (CRP) in the US

We have submitted comments showing that a large amount of ex-CRP land appears to have come into production in the US in the last 7 years (see page 5 in Attachment 3).[32] The GTAP model is capable of accessing this land, but in the ARB version of the model the option to access this land within GTAP has been turned off. It is very straightforward to turn this option on. The Babcock/Iqbal study also identifies ex-CRP land as a factor in confirming that there has been no forest or pasture transformations to cropland in the US (see pages 29-30 of the study). Implementation of the CRP land option in GTAP reduces emissions for the ARB average case from 17.22 gCO2/MJ to 16.35 g CO2e/MJ.

If ARB decides to use the Babcock/Iqbal study as a filter to determine regions with forest to crop and pasture to crop transitions, then there is no need to modify GTAP to access CRP lands. However, if ARB decides not to use the Babcock/Iqbal study as a filter, then the GTAP modeling used by ARB should allow the model to access CRP land, because that is what has already happened.

Cropland/Pasture Elasticity (PAEL)

In its modeling scenarios, ARB is only examining cropland/pasture elasticity values of 0.2/0.1 (US/Brazil) and 0.4/0.2. The 0.4/0.2 levels are Purdue's default or best

[32] "Comments on ARB's March 11 Workshop on The Low Carbon Fuel Standard, Air Improvement Resource Inc., April 6, 2014 (provided in Attachment 4).

estimate. So, ARB is examining the Purdue best estimate and one-half that level (lower levels increase the iLUC emissions).

We indicated in our comments on the September 29 workshop and also in the November 20 workshop, that ARB should estimate emissions for three PAEL levels for the US and Brazil. Two of the levels are the same as the ARB's current levels, the third one is 0.6/0.3. ARB had previously planned on using the 0.6/0.3 values. In response to our question as to why PAEL levels of 0.6/0.3 were dropped from the analysis, ARB indicated that there was a problem with the run, and promised further information on this. To date, we have not seen that information.

We therefore ran the 0.6/0.3 case using the ARB average price yield elasticity of 0.19 and the baseline ETA value. We encountered no problems with the run, and obtained emissions of 15.55 gCO2e/MJ (as compared to 17.22 g/MJ for the ARB average case using PAEL levels of 0.3/0.15). We therefore recommend that ARB re-instate the 0.6/0.3 PAEL case in its scenario runs, or explain in detail what its concerns are with this case.

Longer-Term Items

ARB appears to have only 4 items on its agenda for longer-term study (see page 29 of the November 20 workshop handout):

- Address forestry issue in the model
- Account for fertilizer, livestock, and paddy rice emissions
- Include analysis for cellulosic feedstocks
- Develop and validate dynamic GTAP model

Notably absent from this list are all the items which Babcock/Iqbal identify as primary drivers of less Forest-to-Crop and Pasture-to-Crop transitions (and thus the overall iLUC emissions of biofuels) in many regions of the world, such as (1) multiple cropping (double- and even triple-cropping), (2) use of temporary fallow/idle land, (3) less land that is planted and not harvested, and (4) the use of CRP land in the US. In addition, stakeholders reviewing ARB's iLUC estimates have made numerous comments about multiple cropping, the use of CRP, idle land, etc. Many of these items were identified 4-5 years ago by various stakeholders. None should be deferred from action in the current rulemaking, if ARB's intent is to use the best available scientific information and analysis, as A.B. 32 requires.

The amount of temporary or fallow land can actually be computed from the GTAP land cover. In GTAP there are two layers of information on cropland; land cover and harvested area. Any land which has been cultivated in the past is included in the cropland category under the land cover header. This category of land includes all types of cropland (cultivated and idled land such as planted but not harvested, cropland-pasture, CRP, or fallow). The cropland area is generally not divided into different types (except partially for the US and Brazil). The second layer is harvested area. Harvested area refers to the cropland that is harvested in the base year (i.e. 2004).

The version of GTAP used by CARB has cropland-pasture for the US and Brazil and CRP area for the United States added to the harvested land layer. The model does not allow conversion of CRP land to crop production (the model keeps it under the conservation program). However, cropland-pasture which is used for grassing tasks can be converted back to crop production. Cropland-pasture in the other regions of the world and fallow land (either deliberately not planted or having a harvest failure) are not included in the harvested land layer. The model currently has no capability of accessing this land for increased crop production even though it is probably the most likely land to respond to higher crop demand and is land that could be brought into production without any land use change.

In some areas of the world two or more crops can be harvested from the same land in a given year. In these areas, the harvested land may be greater than the cropland area. While some regions may have both fallow land and double-cropped land from this data we can only show the net fallow land (i.e., net cropland not in crops) and the net double-cropped land. A summary of these lands by model region is shown in Table 6.[33]

[33] Darlington, Kahlbaum, O'Connor, and Mueller, "Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project Model, August 30,2013.

Table 6. GTAP Land Summary (Ha)				
GTAP Region	Cropland	Harvested Area	Net Cropland Not in Crops	Net Double-Cropped
USA	175,807,007	167,059,000	8,748,007	
EU27	124,830,687	115,729,000	9,101,687	
BRAZIL	60,724,257	86,403,000		-25,678,743
CAN	39,573,515	33,514,000	6,059,515	
JAPAN	3,680,435	4,185,000		-504,565
CHIHKG	140,644,611	160,840,000		-20,195,389
INDIA	171,418,998	186,799,000		-15,380,002
C_C_Amer	56,671,461	26,687,000	29,984,461	
S_o_Amer	58,603,527	56,585,000	2,018,527	
E_Asia	5,190,174	4,852,000	338,174	
Mala_Indo	71,571,068	35,999,000	35,572,068	
R_SE_Asia	53,207,433	60,163,000		-6,955,567
R_S_Asia	46,956,517	43,712,000	3,244,517	
Russia	124,542,334	81,229,000	43,313,334	
Oth_CEE_CIS	111,522,274	94,998,000	16,524,274	
Oth_Europe	933,565	1,160,000		-226,435
MEAS_NAfr	53,633,308	49,933,000	3,700,308	
S_S_AFR	211,016,073	175,792,000	35,224,073	
Oceania	33957545	42,181,000		-8,223,455
Total	1,544,484,789	1,427,818,000	193,828,945	-77,164,156

In addition, ARB currently assumes that cropland-pasture that is converted to cropland experiences 50% of the emissions of conversion of permanent pasture. This is strictly an assumption. Purdue currently estimates conversion of cropland-pasture has the same emissions as crop-to-crop conversions. This should also be a focus of future research.

Appendix B

Comments on the CA-GREET 2.0 Model
February 10, 2014

ARB staff released a draft report comparing GREET1.8b, GREET12013, and CA-GREET 2.0 on October 10. In addition, staff released the GREET 2.0 model for comment. AIR has reviewed some aspects of this model, and offers comments in the following areas:

- GREET2014
- Denaturant Modifications for Ethanol
- DGS Reduced Enteric Emissions Credit

In addition to the above, Professors Bruce Dale and Seungdo Kim reviewed the agricultural chemical and ethanol plant chemical emissions for both corn and cellulose ethanol. Their comments are included in Attachment 1 to this document.

Our combined reviews indicate that ARB has overestimated the direct emissions of both corn ethanol and ethanol made from stover. The implications of overestimating the lifecycle emissions for corn and stover ethanol are that it could lead to shuffling of fuels without any reduction in greenhouse gases and increased costs of compliance with the LCFS.

<u>GREET2014</u>

The CA-GREET 2.0 model is based on the GREET1-2013 model from Argonne. GREET2014 was released by Argonne on October 3, 2014. ARB should examine GREET2014 to determine improvements that should be made to CA-GREET 2.0.

<u>Denaturant Modifications for Ethanol</u>

The amount of denaturant assumed in CA-GREET1.8b was 2.0%. However, in CA-GREET-2.0 the amount of non-ethanol material in ethanol was increased to 5.4%. The 5.4% is assumed to be 2.4% denaturant, at most 1 percent water, at most 0.5 percent methanol, and at most 1.4 percent "other." The 2.9% combination of water, methanol, and "other", is assumed to have the same carbon intensity of CARBOB, so the net effect of this assumption is the same as assuming 5.4% CARBOB in ethanol. The CI of CARBOB is higher than most ethanol pathways, so increasing the denaturant from 2% to 5.4% in effect raises the CI of ethanol (and doubles the denaturant effect).

It is very clear that water does not have the CI of CARBOB. It is also highly unlikely that methanol and "other", whatever the other is, would have the same CI as CARBOB. AIR believes increasing the denaturant to 5.4% is a mistake that unfairly penalizes ethanol. AIR recommends that the denaturant percentage be set to 2.4% in CA-GREET 2.0.

DGS Reduced Enteric Emissions Credit

GREET2013 contains a distiller grains (DGs) credit for the coproduct due to reduced enteric fermentation from livestock from feeding with DGs. Staff is proposing no DGs reduced enteric emissions credit "due to the feeding of animals not being considered in the LCFS pathway LCA system boundary." Staff goes on to say that "...including the feeding of animals in the LCA would require significant analysis and would not only include the enteric emissions or change thereof from business as usual, e.g., other emissions would need to be considered and feed markets would need to be analyzed and updated."

Staff's arguments for not including the enteric emissions credit due to feeding of DGs are weak. First, Staff expands the system boundaries in arbitrary ways already. The Staff has included indirect land use system emissions (iLUC), which cannot be measured, and can only be estimated with a combination of economic modeling and estimates of the carbon released during specific land use changes (i.e., the emission factors of each land use change). Staff has spent a great deal of time and effort on this indirect effect. So, other indirect effects such as reduced enteric fermentation should also be included in Staff's analysis. Second, Argonne has already estimated this effect, and has included it in GREET1-2013.

Staff has no specific criticisms of the effect as estimated in GREET1-2013. Staff say, however, that the primary driver of reduced enteric emissions are shortened lifespan of livestock. Staff is concerned that if feeding DGs increases livestock throughput, then enteric emissions could increase. They also cite studies that show feeding defatted DGs compared to grain feeding causes an increase in N2O emissions from finishing beef cattle, which could reduce the enteric credit.

We recommend that Staff include the DG enteric credit in CA-GREET2.0. It is already included in GREET2013. If Staff have concerns with the effect, then they should develop a better estimate of the effect after finalizing CA-GREET2.0 with the current effect, in much the same way as Staff adopted an iLUC effect in 2009 and have spent some effort in the last 1.5 years attempting to improve it.

We note that there is another very significant effect of enteric fermentation. The economic models show that increasing biofuels requires additional cropland, and much additional cropland comes from pasture and cropland/pasture. This raises livestock prices, thereby reducing total livestock herds and total enteric fermentation emissions. The EPA included this effect in the RFS four years ago. We have repeatedly commented to ARB that the Staff should include this effect as well in its analysis, and Staff has pushed this off to the future. Clearly, there are very significant effects of biofuels on enteric fermentation emissions in two areas – the

DGs effect and the price effect – and ARB has ignored these effects in this analysis. These are very serious shortcomings in the current ARB analysis.

Additional Comments by Bruce Dale and Seungdo Kim

Attachment 1 contains additional comments by Ca-GREET2.0 by Kim/Dale. These comments cover a number of items for both corn ethanol and ethanol made from corn stover.

Table 1 summarizes the Kim/Dale comments and their impacts on CaGREET emissions for both corn ethanol and corn stover.

Table 1. Impacts of the Kim/Dale Recommendations on CaGREET Corn Ethanol and Stover Ethanol Emissions		
Corrections	Corn dry mill pathway [gCO_2/MJ]	Corn stover pathway [gCO_2/MJ]
Current fertilizer rates	-0.67	
1.2. CO_2 emissions from limestone	-0.83 ~ -2.18	
1.3. Nutrient contents in fertilizers	-0.06	-0.05
1.5. Soil N_2O emissions from corn stover in corn ethanol	-0.21	
1.6. Supplement nutrients in corn stover ethanol		-7.98
2.2. Lifecycle GHG emissions of sulfuric acid	-0.47	-0.92
2.3. Cellulase enzyme loading in corn stover ethanol		-1.32 ~ -1.79
2.4. Marginal electricity in corn stover ethanol		-8.07
Total	-2.24 ~ -3.59	-26.4~ -26.9

Attachment 1

Review of lifecycle GHG calculations for corn ethanol and corn stover ethanol in the

CA-GREET2.0 model

November 6, 2014

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The authors reviewed farming nutrient emission rates and the emission rates of chemicals used in corn ethanol production in the CA-GREET 2.0 model. We have a number of comments, which are detailed in this document.

The table below summarizes the emission impacts of our comments.

Summary of suggested numerical corrections to the CARB values

Corrections	Corn dry mill pathway [gCO_2/MJ]	Corn wet mill pathway [gCO_2/MJ]	Corn stover pathway [gCO_2/MJ]
1.1. Current fertilizer rates	-0.67	-0.66	
1.2. CO_2 emissions from limestone	-0.83 ~ -2.18	-0.82 ~ -2.14	
1.3. Nutrient contents in fertilizers	-0.06	-0.06	-0.05
1.5. Soil N_2O emissions from corn stover in corn ethanol	-0.21	-0.21	
1.6. Supplement nutrients in corn stover ethanol			-7.98
2.2. Lifecycle GHG emissions of sulfuric acid	-0.47	-0.46	-0.92
2.3. Cellulase enzyme loading in corn stover ethanol			-1.32 ~ -1.79
2.4. Marginal electricity in corn stover ethanol			-8.07
Total	-2.24 ~ -3.59	-2.22 ~ -3.57	-26.4~ -26.9

Our comments are presented in the next two sections. The first section details comments on agricultural chemicals, and the second section deals with chemicals used in corn ethanol plants.

1. Feedstock production (corn grain and corn stover)

1.1. Fertilizer rates in corn grain production

The fertilizer application rates per bushel of corn in the CA-GREET2.0 model (in cells: Inputs!F281:F283) do not reflect the current corn culture practices in the US.

The CA-GREET2.0 supporting document provides a reference[1] for the fertilizer application rates given in the CA-GREET2.0 model. These values are probably based on available data up to 2005. Unfortunately, the timeframe for the fertilizer application rates was not clearly stated in the reference so we are unable to determine how these California values were generated. Furthermore, newer fertilizer application rates for corn culture practices in 2010 are available and should be used in preference to any earlier values. Thus in this report we have used USDA statistics[2] to estimate the US average 2010 fertilizer application rates per bushel of corn—the most recent time period available. These USDA data are summarized in Table 1. The fertilizer rates in the NASS (USDA study) are slightly lower than those in the CA-GREET2.0 model due to higher corn yields. The NASS fertilizer application rates are 4 – 20% less than the rates in the CA-GREET2.0 model.

Table 1 Fertilizer application rate per bushel of corn produced [2]

	NASS¶	CA-GREET2.0 (in cells: Inputs!F281:F283)
N (gram per bushel)	400.84	415.33
P_2O_5 (gram per bushel)	138.42	147.77
K_2O (gram per bushel)	143.36	172.11

Fertilizer consumption to produce corn silage is excluded from these data.

[1] Wang, Michael Q., Jeongwoo Han, Zia Haq, Wallace E. Tyner, May Wu, and Amgad Elgowainy. "Energy and greenhouse gas emission effects of corn and cellulosic ethanol with technology improvements and land use changes." Biomass and Bioenergy 35, no. 5 (2011): 1885-1896

[2] National Agricultural Statistics Service. http://www.nass.usda.gov/

Using the current fertilizer application rates per bushel of corn from the NASS data summarized in Table 1 reduces the GHG of corn ethanol by 0.67 (0.66) g/MJ in the dry (wet) mill pathway. The detailed calculations are as follows:

The calculations are done in the CA-GREET2.0 spreadsheet model. Replace the fertilizer rates in the CA-GREET2.0 model (in cells: Inputs!F281:F283) by the NASS values in Table 1. Results are summarized in Table 2.

Table 2 Calculations for fertilizer application rates

	Rates from NASS	CA-GREET2.0
GHG associated with fertilizers [gram/MJ] (EtOH!D429)	14.28	14.81
N_2O emissions [gram/MJ] (EtOH!E429)	14.93	15.32
GHG credit of co-products [gram/MJ] (EtOH!G429)	13.21	13.47
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	76.11	76.78

The USDA/NASS statistics[2] also show that fertilizer application rates per bushel (i.e., N, P_2O_5, K_2O applied per bushel of corn produced) have been steadily declining with time. (See Figure 1) Even though total amount of fertilizer applied nationally has increased, the application rate per bushel has actually declined due to higher corn yields. Assuming the trends summarized in Figure 1 have continued, even less total fertilizer use per bushel of corn produced is projected after 2010.

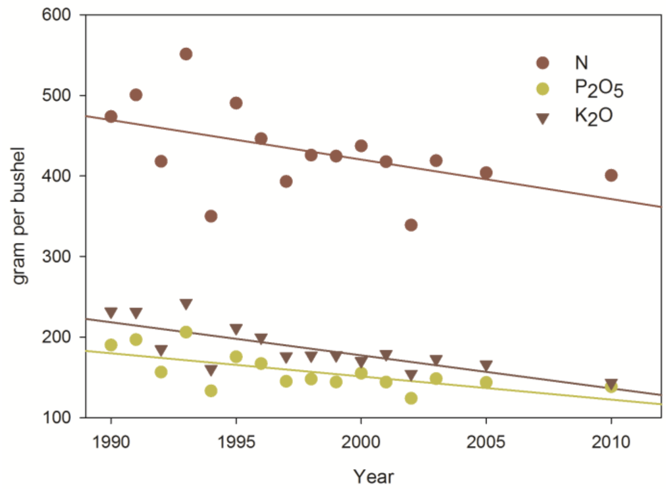

Figure 1 Fertilizer application rates in the US [data source: NASS[2]]

1.2. CO_2 emissions from limestone

Limestone ($CaCO_3$) is the primary agricultural lime used in the US in 2011[3], accounting for about 93% of the total lime applied. The rest is dolomite ($MgCa(CO_3)_2$). The CA-GREET2.0 model incorrectly assumes that 100% of the carbon in limestone that is applied to soil is released to the air as carbon dioxide and fails to account for various soil, water and atmospheric processes that are very relevant. In contrast, a USDA report[4] based on actual, physical processes occurring in soil, water and the atmosphere finds that two-thirds of the carbon in limestone remains in long-term carbon sinks and only one-third of the carbon in limestone is actually released as carbon dioxide.

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[3] United States Environmental Protection Agency (2013) U.S. greenhouse gas inventory report: Inventory of U.S. greenhouse gas emissions and sinks: 1990-2011. United States Environmental Protection Agency, Washington, DC.

[4] USDA (2014) Quantifying Greenhouse Gas Fluxes in Agriculture and Forestry: Methods for Entity-Scale Inventory. , Washington, DC.

For example, dissolved CO_2 resulting from root and microbial respiration exists in equilibrium in soil water with H_2CO_3. This slightly acidic H_2CO_3 reacts with limestone[5] as described below in Equations (1) and (2).

$$CO_2 + H_2O \rightarrow H_2CO_3 \quad (1)$$

$$CaCO_3 + H_2CO_3 \rightarrow Ca^{2+} + 2HCO_3^- \quad (2)$$

Dissolved HCO_3^- is stable and is transported to the ocean by rivers and streams. In the ocean, this carbon is sequestered for time periods of decades to centuries[4].

In a separate study, West and McBride[6] also estimate the carbon dioxide emission factors for limestone applied by accounting for leaching and transport by rivers to the ocean. The carbon dioxide emission factors for limestone applied to agricultural land given in their study are 0.059 kg C/kg limestone applied for limestone and 0.064 kg C/kg dolomite applied for dolomite. These are the emission values currently used in the U.S. National GHG Inventory[3]. However, they do not include the entire range of biophysical processes covered by the USDA report[4].

CA-GREET2.0 should use the most comprehensive, scientifically-valid calculations available to estimate the GHG emissions of agricultural lime application. We believe

[5] Hamilton, Stephen K., et al. "Evidence for carbon sequestration by agricultural liming." Global Biogeochemical Cycles 21: 1 - 12 (2007).

[6] West TO, McBride AC (2005) The contribution of agricultural lime to carbon dioxide emissions in the United States: dissolution, transport, and net emissions. Agr Ecosyst Environ 108:145–154

those are the values given by the USDA report[4]. The carbon dioxide emission factors for agricultural limestone applied are summarized in Table 3 below.

Table 3 Carbon dioxide emission factors for agricultural limestone application

	Carbon dioxide emission from Limestone [kg CO_2/kg]
CA-GREET2.0	0.44
USDA[4]	-0.15
GREET2014[7] & West and McBride[6]	0.216

Using the carbon dioxide emission factors from the USDA process-based report[4] and the GREET2014 model[7] reduces the GHG of corn ethanol by 0.83 and 2.18 (0.82 and 2.14) g/MJ in the dry (wet) mill pathway, respectively. The detailed calculations are as follows:

Replace the carbon dioxide emission factors in the CA-GREET2.0 model (in cells: EtOH!F380, 44/100) by the factors in Table 3. Results are summarized in Table 4.

Table 4 Calculations for lime application

	Factor from USDA report[4]	Factor from GREET2014[7]	CA-GREET2.0
CO_2 from $CaCO_3$ use [gram/bushel] (EtOH!F380)	-169	249	506

[7] Argonne National Laboratory (2014) Greenhouse gases, regulated emissions, and energy use in transportation (GREET) computer model 2014.

GHG associated with fertilizers [gram/MJ] (EtOH!D429)	11.81	13.66	14.81
GHG credit of co-products [gram/MJ] (EtOH!G429)	12.66	13.16	13.47
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	74.60	75.94	76.78

1.3. Nutrient contents in N and P_2O_5 fertilizers

The CA-GREET2.0 model assumes that N fertilizer consists of ammonia, urea, ammonium nitrate, urea-ammonium nitrate solution, mono-ammonium phosphate, and di-ammonium phosphate, and P fertilizer consists of mono-ammonium phosphate, and di-ammonium phosphate as summarized in Table 5. However, the nutrient contents in some of these fertilizers are not given correctly in the CA-GREET2.0 model. The nitrogen content in di-ammonium phosphates is 18%[8], not 16% as given in the CA-GREET2.0 model. The P_2O_5 contents in mono- and di-ammonium phosphates are 48 -61% (the most common value is 52%) and 46%[8], respectively.

Table 5 Fraction and nutrient content of N and P_2O_5 fertilizers in CA-GREET2.0 [basis: N for N fertilizer, P_2O_5 for P fertilizer]

N fertilizer	Ammonia	Urea	Ammonium Nitrate	Urea-Ammonium Nitrate Solution	Mono-ammonium Phosphate	Di-ammonium Phosphate
Fraction	0.31	0.23	0.04	0.32	0.04	0.06
N content (%)	82.4%	46.7%	35.0%	-	11.0%	16.0% (Ag_Inputs!AC74)

[8] Penn State Extension, Nitrogen Fertilizers. http://extension.psu.edu/agronomy-guide/cm/tables/table-1-2-11

P_2O_5 fertilizer		Mono-ammonium Phosphate	Di-ammonium Phosphate
Fraction		0.5	0.5
P_2O_5 content (%)		48.0% (Ag_Inputs!AE74)	48.0% (Ag_Inputs!AF74)

Using the correct nutrient contents reduces the GHG of corn ethanol by 0.06 (0.06) g/MJ in the dry (wet) mill pathway and reduces the GHG of corn stover ethanol by 0.05 g/MJ. The detailed calculations are as follows:

Replace the nutrient content in the CA-GREET2.0 model (in cells: Ag_Inputs!AC74, Ag_Inputs!AE74, Ag_Inputs!AF74) by the corrected values (18% for Ag_Inputs!AC74; 52% for Ag_Inputs!AE74; 46% for Ag_Inputs!AF74). Results are summarized in Table 6.

Table 6 Calculations for nutrient content

	Corrected values	CA-GREET2.0
Corn ethanol in the dry mill pathway		
GHG associated with fertilizers [gram/MJ] (EtOH!D429)	14.72	14.81
N_2O emissions [gram/MJ] (EtOH!E429)	15.32	15.32
GHG credit of co-products [gram/MJ] (EtOH!G429)	13.44	13.47
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	76.72	76.78
Corn stover ethanol		

GHG associated with fertilizers¶ [gram/MJ]	10.06	10.11
GHG of corn stover ethanol§ [gram/MJ]	14.63	14.68

¶ Sum of GHG from cells EtOH!CJ371:EtOH!CN379 divided by ethanol yield (EtOH!G141) and converted to MJ
§ Sum of cells EtOH!AG412:AH412

1.4. Emissions of N and P_2O_5 fertilizers

Mono- and di-ammonium phosphate fertilizers contain both N and P_2O_5 nutrients. Therefore, the CA-GREET2.0 model probably uses allocation factors to assign emissions to either N or P_2O_5. However, there is no background information given in the CA-GREET2.0 model to describe and define how these putative allocation factors were chosen. The choice of allocation factors should be transparent and readily available through the CA-GREET2.0 model.

The amounts of N and P_2O_5 fertilizers applied based on the fractions of each fertilizer used in agriculture and their respective nutrient contents as given by CA-GREET2.0 are not equal to those of N and P_2O_5 fertilizers used in corn grain production as seen in Table 7. Emissions of N and P_2O_5 fertilizers (in cells: EtOH!D365:E379) are associated with using 439.8 g of N fertilizer and 284.2 g of P_2O_5 fertilizer, not 415.33 g of N fertilizer and 147.77 g of P_2O_5 fertilizer. Therefore, emissions of N and P_2O_5 fertilizers (in cells: EtOH!D365:E379) do not represent emissions associated with the actual amounts of N (415.33 gram/bushel) and P_2O_5

(147.77 gram/bushel) used in corn grain production and should be recalculated to be consistent with current actual corn grain production practice.

Table 7 Quantities of N and P_2O_5 fertilizers in CA-GREET2.0 [basis: N for N fertilizer, P_2O_5 for P_2O_5 fertilizer]

	N fertilizer		P_2O_5 fertilizer	
	Nutrient [gram/bushel]			
	N	P_2O_5	N	P_2O_5
Ammonia	124.3			
Urea	92.2			
Ammonium Nitrate	16.0			
Urea-Ammonium Nitrate Solution	128.3			
Mono-ammonium Phosphate	16.0	70.0	15.9	69.2
Di-ammonium Phosphate	24.1	72.2	23.1	69.2
Sum	400.8	142.1	38.9	138.4
Total N	400.8 + 38.9 = 439.8			
Total P_2O_5	142.1 + 138.4 =284.2			

1.5. Soil N_2O emissions from corn stover due to corn ethanol production

The CA-GREET2.0 model uses the emission factor (1.325%) for N_2O according to the IPCC guidelines[9], which include direct and indirect N_2O emissions. The CA-GREET2.0 model applies this emission factor to both inorganic fertilizer and corn stover. However, the IPCC guideline[9]

does not include volatile nitrogen loss from crop residues. This volatile nitrogen is lost to the air and is thus not available for soil microbes to convert it to N_2O. Thus, the N_2O emission factor for corn stover should be reduced to 1.225%. The data surrounding this correction to the CA-GREET2.0 calculations are summarized in Table 8. Box 1 below quotes the relevant procedures for calculating indirect N_2O emissions as given in the IPCC guideline[9].

Table 8 Emission factor

	IPCC[9]	CA-GREET2.0
Fertilizer		
Direct N_2O from fertilizer	0.01	0.01
Indirect N_2O from volatized N from fertilizer	0.001 (=0.1*0.01)	0.001 (=0.1*0.01)
Indirect N_2O from leached N from fertilizer	0.00225 (=0.3*0.075)	0.00225 (=0.3*0.075)
Emission factor for fertilizer	0.01325	0.01325
Crop residues		

[9] Intergovernmental Panel on Climate Change (2006) 2006 IPCC guidelines for national greenhouse gas inventories. http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

Direct N_2O from crop residues	0.01	0.01
Indirect N_2O from volatized N from crop residues	-	0.001 (=0.1*0.01)
Indirect N_2O from leached N from crop residues	0.00225 (=0.3*0.075)	0.00225 (=0.3*0.075)
Emission factor for crop residues	0.01225	0.01325

Box 1. Indirect N_2O calculations (quoted from the IPCC guideline[9])

Volatilization, $N_2O(ATD)$

N_2O FROM ATMOSPHERIC DEPOSITION OF N VOLATILISED FROM MANAGED SOILS (TIER 1)

$$N_2O(ATD){-}N = [(FSN \bullet FracGASF) + ((FON + FPRP) \bullet FracGASM)] \bullet EF4$$

Where:

$N_2O(ATD)–N$ = annual amount of $N_2O–N$ produced from atmospheric deposition of N volatilized from managed soils, kg $N_2O–N$ yr^{-1}

FSN = annual amount of synthetic fertilizer N applied to soils, kg N yr^{-1}

FracGASF = fraction of synthetic fertilizer N that volatilizes as NH_3 and NOx, kg N volatilized (kg of N applied) $^{-1}$

FON = annual amount of managed animal manure, compost, sewage sludge and other organic N additions applied to soils, kg N yr^{-1}

FPRP = annual amount of urine and dung N deposited by grazing animals on pasture, range and paddock, kg N yr^{-1}

FracGASM = fraction of applied organic N fertilizer materials (FON) and of urine and dung N deposited by grazing animals (FPRP) that volatilizes as NH_3 and NOx, kg N volatilized (kg of N applied or deposited) $^{-1}$)   EF4 = emission factor for N_2O emissions from atmospheric deposition of N on soils and water surfaces,   [kg N– N_2O (kg NH_3–N + NOx–N volatilized) $^{-1}$]

This correction reduces the GHG of corn ethanol by 0.21 (0.21) g/MJ in the dry (wet) mill pathway. The detailed calculations are as follows:

Replace the emission factor for corn stover in the CA-GREET2.0 model (in cells: EtOH!D382) by the IPCC emission factor given in Table 8 above. Results are summarized in Table 9.

Table 9 Calculations for nutrient content

	IPCC value	CA-GREET2.0
Corn ethanol in the dry mill pathway		
N2O from nitrogen fertilizer, and above and below ground biomass [gram/bushel] (EtOH!D382)	11.374	11.596
N_2O emissions [gram/MJ] (EtOH!E429)	15.03	15.32
GHG credit of co-products [gram/MJ] (EtOH!G429)	13.39	13.47
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	76.56	76.78

1.6. Supplemental nutrients in corn stover ethanol production

In the CA-GREET2.0 model, supplemental nutrients (i.e., N, P_2O_5, K_2O) are added in the subsequent growing season to replace nutrients that are assumed to be lost when corn stover is collected to produce corn ethanol. The amount of the supplement nutrients required is assumed to be exactly equal to the nutrient content of the corn stover removed. However, the supplemental nutrients required depend on actual crop management practices used in the subsequent growing season. According to USDA statistics[10], only 33% of cornfields function as cornfields ("corn on corn") in the subsequent growing season, while about 48% of cornfields are used to grow soybeans in the subsequent growing season. Approximately 2.4% of cornfields are converted to developed land, open water or left fallow in the subsequent growing season. This information is summarized in Figure 2.

Supplemental N nutrients in the following growing season are therefore not necessary for croplands used to produce soybeans even though the nitrogen content in corn stover was removed. Furthermore, supplemental nutrients are not necessary for lands converted to developed land, open water or left fallow. Therefore, supplemental N nutrients are needed in only 49% (=100% - 48% (soybean) - 2.4% (fallow, etc.)) of corn-producing croplands next year, and the supplemental P and K nutrients are needed in only 98 % (100% – 2.4% (fallow, etc.)) of croplands from cornfields next year. By accounting properly for the actual use of corn land in the subsequent growing season, the GHG of corn stover ethanol is reduced by 7.98 g/MJ. The detailed calculations are as follows:

[10] USDA, CropScape - Cropland Data Layer. http://nassgeodata.gmu.edu/CropScape/

Multiply the fertilizer used in the CA-GREET2.0 model (in cells: EtOH!H20:H22) by 0.49 for N, and 0.98 for P_2O_5 and K_2O, respectively. Results are summarized in Table 10 below.

Table 10 Calculations for supplemental nutrients required for continuous corn

	Corrected values	CA-GREET2.0
GHG associated with fertilizers¶ [gram/MJ]	6.01	10.11
N2O from nitrogen fertilizerΓ [gram/MJ]	-3.87	0
GHG of corn stover ethanol§ [gram/MJ]	6.71	14.68

¶ Sum of GHG from cells EtOH!CJ371:CN379 divided by ethanol yield (EtOH!G141) and converted to MJ
Γ cells EtOH!CJ382 converted to MJ
§ Sum of cells EtOH!AG412:AH412

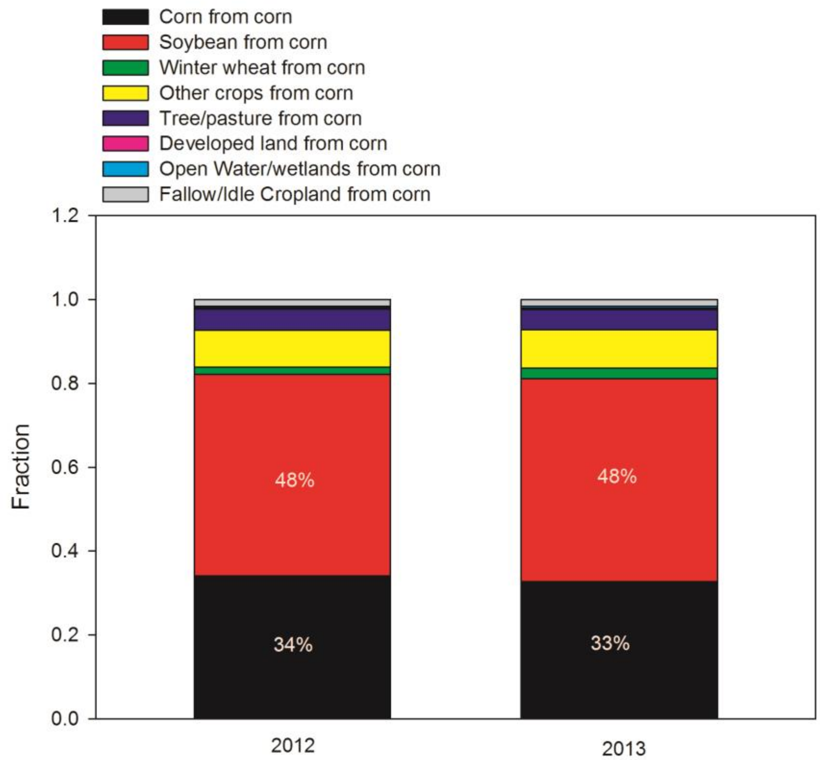

Figure 2 Land use changes in corn cultivation [data source: USDA[10]]

2. Ethanol production (dry mill and cellulosic biorefinery)

2.1. CO_2 emissions from urea displaced by DDGS

Enzymes from bacteria in cattle rumen, specifically urease, break down urea to CO_2 and ammonia, and CO_2 is released. Displacing urea by DDGS avoids those CO_2 emissions. However, the CA-GREET2.0 does not include a credit for CO_2 emissions from urea displaced by DDGS. Even though this value is very small, it should be included in the model for completeness.

2.2. Lifecycle GHG emissions of sulfuric acid in corn stover ethanol

About 250 grams of sulfuric acid (EtOH!CR361) are used to produce one gallon of corn stover ethanol. A plant producing sulfuric acid generally exports thermal energy (steam) and electricity, and therefore its net energy use is negative[11, 12]. However, the CA-GREET2.0 model does not include the correct energy credits for the exported energy in calculating lifecycle emissions of sulfuric acid. Assuming that 2.1 MMBTU per ton of sulfuric acid[11] is exported from a sulfuric acid plant, the GHG of corn ethanol is reduced by 0.47 (0.46) g/MJ in the dry (wet) mill pathway, and the GHG of corn stover ethanol is reduced by 0.92 g/MJ. The detailed calculations are as follows:

Add an energy credit (2.1 MMBTU/ton) in the cell Ag_Inputs!R26 in the CA-GREET2.0 model. Results are summarized in Table 11. In the CA-GREET2.0 model, sulfuric acid is used to manufacture the phosphorus-containing fertilizers.

The lifecycle GHG of sulfuric acid also affects lifecycle GHG of mono- and di-ammonium phosphates. Correcting the lifecycle GHG of sulfuric acid also changes the GHG of corn ethanol.

Table 11 Calculations for sulfuric acid

	Corrected values	CA-GREET2.0
Corn ethanol in the dry mill pathway		
GHG associated with fertilizers [gram/MJ] (EtOH!D429)	14.16	14.81

[11] USDOE, Energy and Environmental Profile of the U.S. Chemical Industry, 2000.
[12] National Renewable Energy Laboratory. U.S. Life Cycle Inventory Database.

GHG credit of co-products [gram/MJ] (EtOH!G429)	13.29	13.47
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	76.30	76.78
Corn stover ethanol		
GHG associated with fertilizers¶ [gram/MJ]	9.73	10.11
GHG of biorefineryΓ [gram/MJ]	13.65	14.19
GHG of corn stover ethanol§ [gram/MJ]	13.76	14.68

¶ Sum of GHG from cells EtOH!CJ371:CN379 divided by ethanol yield (EtOH!G141) and converted to MJ
Γ Sum of GHG from cells EtOH!CR371:CR380
§ Sum of cells EtOH!AG412:AH412

2.3. Cellulase enzyme loading in corn stover ethanol

Recent authoritative studies[13, 14] show that current cellulase enzyme loadings range from 17.5 - 19.9 mg per g of cellulose for dilute acid pretreatment of corn stover followed by enzymatic hydrolysis and fermentation of the sugars to ethanol. This enzyme application rate is equivalent to about 72 – 83 g enzyme per gallon of

[13] Humbird D, Davis R, Tao L, Kinchin C, Hsu D, Aden A, Schoen P et al. Process design and economics for biochemical conversion of lignocellulosic biomass to ethanol: Dilute-acid pretreatment and enzymatic hydrolysis of corn stover. Colorado: National Renewable Energy Laboratory; 2011.
[14] da Costa Sousa L, Jin M, Uppugundla M, Bokade V, Humpula JF, Gunawan C, Foston MB et al. Extractive AFEX™ (E-AFEX™) pretreatment: a unified approach for resolving bottlenecks to efficient cellulosic bioethanol production. New Orleans, LA: 34th Symposium on Biotechnology for Fuels and Chemicals; 2012.

ethanol. However, the enzyme loading used the CA-GREET2.0 model (cells EtOH!CR359) is 113.4 g per gallon of ethanol, which is higher than the current enzyme technologies actually require. Applying current enzyme technologies as summarized in the 2011 National Renewable Energy Laboratory study reduces emissions by 1.32 – 1.79 g/MJ. The detailed calculations are as follows:

Replace the enzyme loading rate in the CA-GREET2.0 model (cells EtOH!CR359) by new enzyme loading values. Results are summarized in Table 12.

Table 12 Calculations for enzyme loading

	Current technologies		CA-GREET2.0
Enzyme loading [g per gallon]	72	83	113.4
Ethanol yield [gallon/dry ton]	70	79	80
GHG of biorefineryΓ [gram/MJ]	12.39	12.87	14.19
GHG of corn stover ethanol§ [gram/MJ]	12.89	13.37	14.68

Γ Sum of GHG from cells EtOH!CR371:CR380
§ Sum of cells EtOH!AG412:AH412

2.4. Marginal electricity in corn stover ethanol

The CA-GREET2.0 model assumes that excess electricity from a cellulosic biorefinery displaces US average electricity demand. However, it is more reasonable to assume that excess electricity would displace marginal electricity, not US average electricity, which consists of electricity from many different energy sources (i.e., fossil fuel, nuclear, renewable energy sources, and hydro). Excess electricity from a cellulosic biorefinery will likely displace electricity from a coal or natural gas-fired power plant, not electricity from nuclear power plant. A nuclear power plant must keep its electricity production level constant at all times. In contrast, marginal electricity is electricity from a power plant which can be brought on line quickly so that the power plant can respond to changing demand for electricity. Nuclear plants and hydroelectric stations are thus ruled out as suppliers of marginal electricity—they can only satisfy base load electricity demand. Electricity from renewable energy sources such as wind and solar are also excluded as sources of marginal electricity because of renewable energy certificates.

Therefore, the marginal electricity replaced by excess electricity from a cellulosic biorefinery would be marginal electricity derived from burning fossil fuels (i.e., coal, petroleum, natural gas). The fuel mix used for marginal electricity production is 64% coal, 34% natural gas and 2% petroleum. These percentages are based on electricity fuel mixes given in the CA-GREET2.0 model. When marginal electricity generated from these fossil fuels is displaced by excess electricity from a cellulosic biorefinery, the GHG of corn stover ethanol is reduced by 8.07 g/MJ. The detailed calculations are as follows:

Create new sheet for marginal electricity in the CA-GREET2.0 model. The new sheet is named “marginal elec”. Replace the electricity fuel mixes in the cells (marginal elec!C56:C72) by marginal fuel mixes - coal (64%), natural gas (34%), petroleum

(2%), others (0). Replace emissions associated with electricity (EtOH!CS371:CS379) by emissions of marginal electricity. Results are summarized in Table 13.

Table 13 Calculations for marginal electricity

	Marginal electricity	CA-GREET2.0
GHG creditΓ [gram/MJ]	-27.54	-19.47
GHG of corn stover ethanol§ [gram/MJ]	6.62	14.68

Γ GHG from cells EtOH!CS371:CS379 and converted to MJ
§ Sum of cells EtOH!AG412:AH412

Appendix C

Review of the Sugar Cane Ethanol Pathways in CA-GREET 2.0

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Date: February 2, 2015

EXECUTIVE SUMMARY

The California Air Resources Board (Board/ARB) is proposing to re-adopt the Low Carbon Fuel Standard (LCFS) regulation and to include updates and revisions compared to the previous regulation. The ARB staff will bring a new LCFS regulation to the Board for consideration in February 2015. The proposed LCFS regulation will contain revisions to the 2010 LCFS as well as new provisions designed to foster investments in the production of the low-CI fuels, offer additional flexibility to regulated parties, update critical technical information, simplify and streamline program operations, and enhance enforcement.

To address these issues with fuel pathway certifications, staff is proposing a two-tiered system in which conventionally produced first-generation fuels, such as starch- and sugar-based ethanol, would fall into the first tier. Next-generation fuels, such as cellulosic alcohols, would fall into the second tier.

ARB has stated that the Tier 1 process simplifies and expedites the certification process by providing applicants with a streamlined CI calculator that computes pathway CIs using a base set of input parameters needed to determine a Tier 1 pathway CI. This method will use the CA-GREET 2.0 model. This model is a California version of the GREET1 2013 model.

Scope of Work

This work reviews the sugarcane ethanol pathways in the new CA GREET model to ensure that they function properly and utilize the best available science. The review has considered the following questions.

> **Are the pathways consistent?**
>
> It is important that the model uses the same basic approach, including system boundaries and assumptions for all of the ethanol pathways and ideally all of the fuel pathways.
>
> **Does the model ask for the key input parameters?**
>
> The model will use a combination of default values and user defined inputs to model specific plants. It will be important that all of the important parameters that change from one plant configuration to another are user defined inputs and are not default values.
>
> **Does the model reflect the actual practices?**
>
> The model must include all of the actual steps in the production process for it to be useful. If it doesn't, some plants will not be able to generate accurate values.
>
> **Does the model have the correct background data and are the calculations correct?**
>
> Finally it is important that the model contains the best available background data and that the model functions properly. Background data would include the default values, biomass and fuel characteristics, and other inputs.

A significant number of issues were identified. Most of the issues results in the model returning values that are lower than what would be returned if the issues were addressed properly.

Sugar Cane Farming Summary

The CA GREET model does not apply different energy use factors to sugar cane farming even though the two scenarios with mechanical harvesting require almost twice the energy of a manual harvest system. A mechanical harvest system with 100% of the energy supplied by diesel fuel will have GHG emissions of 7.54 g CO_2eq/MJ.

There is evidence that the crop residues that are left on the field are reducing the synthetic nitrogen that is required. The proportion of nitrogen from fertilizer and from crop residue should vary depending on whether or not there is straw burning. The CA GREET model is assuming that there is no difference in nitrogen requirements between burned and unburned fields, an unlikely scenario.

Although there is significant uncertainty regarding the appropriate N_2O emission factor for sugar cane production, the best information in the peer reviewed literature would suggest that the 1% EF1 factor used by CARB is too low. The impact of increasing this to 1.5% is an increase in sugar cane N_2O emissions of 2.83 g CO_2eq/MJ.

Straw Burning Summary

The straw burning emissions appear to be too low by about 4.42 g CO_2eq/MJ as a result of using the IPCC emission factors for Ag residue burning rather than the values for grassland and savanna burning. This increase would be reduced to about 2.5 g CO_2eq/MJ if the nitrogen from the burned straw was not returned to the soil as discussed in the previous section.

Cane Transport Summary

The model should be changed so that the share of the delivery of cane by medium duty trucks and by heavy duty trucks is a user input. The truck energy requirements are the same as for corn ethanol.

Ethanol Production Summary

There are several errors in the CA GREET model related to the transfer of information from the T1 Calculator sheet to the core of the model. These include:

1. Nuclear and biomass power shares of the power generation are transposed when they are transferred to the ETOH sheet.
2. The inputs for sulphuric acid and ammonia are input into the cells for enzymes when they move from the T1 Calculator sheet to the ETOH sheet. Entering non-zero values will produce extremely high and erroneous GHG emissions.

There is also the potential for misinterpretation of the input values. The input for Residual oil is really the quantity of used lubricants that are burned in the plant and not the input of residual oil.

The quantity of biomass that is burned at the plants is hard coded in the model. Not all mills burn all of the bagasse on site; some sell a portion to other local industries. The emissions for these operations will be overestimated. The biomass from the T1 Calculator sheet is transferred to the ETOH sheet, but once it goes there it is not included in any calculations. A proper modelling would require the mills to enter the bagasse consumed and not hard code those quantities. The current model would underestimate the emissions from mills that imported bagasse from another facility or used some straw from the fields to produce more electric power for export.

Transportation Summary

There are issues with the ocean shipping calculations in GREET for many of the fuels, including sugarcane ethanol. The issues for sugar cane ethanol include:

1. The shipment size of 22,000 tons is too high and is not a user input.
2. Ethanol, uniquely of all of the fuels in CA GREET, is not charged with a backhaul.
3. The energy use for ocean shipping is calculated but the calculations underestimate the energy used by a significant amount.
4. Energy use in the model is 145 BTU/ton-mile. Data from the IMO suggests that this should be 335 BTU/ton-mile plus 283 BTU/ton-mile for the backhaul. This would increase the ocean shipping emissions by 17.0 g CO_2eq/MJ, a very significant difference.

Summary

With respect to the four questions that were investigated we find that:

1. There are inconsistencies between some aspects of the sugarcane ethanol pathway and all other pathways.
2. There are key input parameters that should be specified by the user of the model. These would include; the share of cane transported by MD and HD trucks, the ocean shipment size, and confirming that a backhaul is always provided.
3. The model does not reflect actual practice. The lack of change in the farming emissions with the different practices that are employed is problematic. The ocean shipping size is double the typical shipments.
4. The background data in the model is not accurate. Although the biggest issue is with the energy used for ocean shipping, the emission factor applied to cane burning should also be changed.

In addition, there are some programming errors in the calculator that need to be adjusted. The following two tables itemize the changes that should be made to the model.

Table ES- 1 Summary of Changes - Farming

Stage	Manual Harvest			Mechanical Harvest		
	Default	Revised	Change	Default	Revised	Change
All Diesel	4.65	5.39	0.74	4.65	5.39	0.74
Extra Diesel for Mech Harvest					7.54	2.15
Extra N Fert for manual	3.22	4.43	1.21			
N_2O from extra N	2.88	3.96	1.08			
Total			3.03			2.89

Table ES- 2 Changes to Rest of Pathway

Item	Default	Revised	Change
N_2O EF	7.48	10.31	2.83
Residue Leaching		7.13	-0.35
Straw Burning EF	10.06	14.42	4.36
Power Export	-0.72	-0.76	-0.04
Shipping			
Backhaul (default value)	7.16	11.41	4.25
Ship size (default value)		18.88	7.47
Int'l Marine Org. Energy		24.15	5.27
Total			23.79

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1. INTRODUCTION

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Based on stakeholder comments received in both the original 2009 rulemaking and the 2011 amendments, the Board directed staff in Resolutions 09-31 and 11-39 to consider revisions to the regulation in a number of specific areas, including the approval of additional fuel pathways. Additionally, staff has indicated that it has conducted internal reviews of lessons learned and has been assessing what has changed since the initial implementation of the LCFS. It is evident that evaluating fuel pathways is very resource-intensive.

Furthermore, stakeholders have expressed concerns that many of the Method 2 pathways in the Lookup Table and on the Method 2 web site are not available for wider use by regulated parties.

In order to attempt to address these issues with fuel pathway certifications, staff is proposing a two-tiered system in which conventionally produced first-generation fuels, such as starch- and sugar-based ethanol, would fall into the first tier. Next-generation fuels, such as cellulosic alcohols, would fall into the second tier.

The ARB staff has stated that the Tier 1 process simplifies and expedites the certification process by providing applicants with a streamlined CI calculator that computes pathway CIs using a base set of input parameters needed to determine a Tier 1 pathway CI. This method will use the CA-GREET 2.0 model. This model is a California version of the GREET1 2013 model.

1.1 SCOPE OF WORK

This work reviews the sugarcane ethanol pathways in the new CA GREET model to ensure that they function properly and utilize the best available science. The review has considered the following questions.

Are the pathways consistent?

It is important that the model uses the same basic approach, including system boundaries and assumptions for all of the ethanol pathways and ideally all of the fuel pathways.

Does the model ask for the key input parameters?

The model will use a combination of default values and user defined inputs to model specific plants. It will be important that all of the important parameters that change from one plant configuration to another are user defined inputs and are not default values.

Does the model reflect the actual practices?

The model must include all of the actual steps in the production process for it to be useful. If it doesn't, some plants will not be able to generate accurate values.

Does the model have the correct background data and are the calculations correct?

Finally it is important that the model contains the best available background data and that the model functions properly. Background data would include the default values, biomass and fuel characteristics, and other inputs.

The report follows the structure of the model. The following sections consider the sugarcane farming operations, straw burning, can transportation, ethanol production, and ethanol transport from Brazil to California.

The model contains four basic sugarcane ethanol pathways:

- Sugarcane Ethanol – Base Case
- Sugarcane Ethanol – with Power Export
- Sugarcane Ethanol – Mechanized Harvest
- Sugarcane Ethanol – Mechanized Harvest with Power Export.

The values that are on the T1 Calculator sheet in the user input cells are not necessarily the expected user values for those cells so there are no default values per se for the four pathways. The direct CI values in the following table are therefore indicative of differences between the four pathways. These do not include the denaturant and the ILUC values.

Table 1-1 Sugarcane Ethanol Indicative CI Values

	Base Case	Power Export	Mechanized Harvest	Mechanized Harvest with Power Export
	g CO_2eq/MJ			
Farming energy	4.65	4.65	4.65	4.65
Fertilizers	4.67	4.67	4.67	4.67
N_2O in Soil	7.48	7.48	7.48	7.48
Straw Burning	10.06	10.06	10.06	10.06
Cane Transportation	1.29	1.29	1.29	1.29
Mechanized Harvesting Credit	0.00	0.00	-10.06	-10.06
Filter Cake T&D	0.01	0.01	0.01	0.01
Plant Energy	2.30	2.30	2.30	2.30
Ethanol T&D	7.16	7.16	7.16	7.16
Power Credit	0.00	-0.72	0.00	-0.72
Total	37.62	36.90	27.56	26.84

Not all sugarcane plants will be able to use the calculator as their operations do not fit the four cases. These include fields that are burned and mechanically harvested and mechanically harvested fields that collect some of the residue to supplement the bagasse for power generation. These kinds of plants will have to follow a Tier 2 method.

CARB have also been allowing some plants that produce sugar and ethanol to reduce the sugarcane production emissions through the use of economic allocation between the sugar and the molasses that is used for the ethanol feedstock. The calculator could not be used for those plants. Economic allocation is the least preferred approach under ISO LCA guidelines. The plants that co-produce sugar and ethanol should have the available data on energy use in distillation and in crystallization to be able to undertake the CI calculation without any allocation.

2. SUGAR CANE FARMING

The CA GREET model has no user inputs for farming energy, fertilizer, and N_2O emissions. Nor do these values change with the two process modifiers (mechanical harvest and power credit). This is consistent with the other biofuel pathways, where feedstock production values are fixed by the model, but there is a difference in mechanical vs. manual harvest in terms of the fuel energy used and some other parameters.

2.1 ENERGY

Farming energy in the model is supplied by diesel, LPG, gasoline, natural gas, electricity, and renewable natural gas. The default values and their contribution are summarized in the following table. While one can change the default values, they don't go anywhere in the model. The small amount of natural gas on the T1 Calculator sheet is not included in the model.

Table 2-1 Farming Energy

Fuel	Value, BTU/tonne	GHG emissions, g CO_2eq/MJ
Diesel Fuel	36,385	2.061
Gasoline	11,685	0.654
Natural Gas	20,425	0.954
LPG	17,860	0.881
Electricity	8,550	0.092
Renewable Natural gas	95	0.000
Total	95,000	4.642

The sources for the energy use in farming report the energy consumption as diesel fuel per tonne of cane, so it is not clear where the breakdown of fuel use by fuel type came from. If all of the fuel was diesel fuel, then the emissions would increase to 5.39 g CO_2eq/MJ (an increase of 0.75 CO_2eq/MJ).

The 95,000 BTU/tonne was introduced in GREET1 2011 and was about twice as high as the previous value, which used data from 2002. It was suggested by Dunn et al (2011) that the reason for the increase could be due to the increase in mechanical harvesting. A recent paper by Wang et al (2014) considered changes in the Brazilian sugarcane industry between 2010 and 2020. The diesel fuel parameters used in that study are shown in the following table.

Table 2-2 Sugar Cane Farming Parameters

	2010	2015	2020
Yield, tonnes/ha	70.5	80.0	84.0
Mechanical Harvest rate, %	50	80	100
Diesel Fuel consumption, l/ha	230	280	314
Diesel, l/tonne	3.26	3.50	3.92
Diesel, BTU/tonne	110,600	118,800	133,000

The energy use is all higher than is found in CA GREET. This data indicate that the farming energy for manual harvesting should be about 2.4 l/tonne (81,000 BTU/tonne) and for 100% mechanical harvest it should be at least 3.9 l/tonne (133,000 BTU/tonne) and not the same for both cases. This difference in farming energy should be very simple to implement in the CA GREET model.

2.2 Fertilizers

The fertilizer parameters are also set in CA GREET and are not to be adjusted by users. The default values and their impact on the GHG emissions from the manufacturing of the fertilizers are shown in the following table. The values on the T1 Calculator tab do not leave the sheet.

Table 2-3 Fertilizer Parameters

Component	Input	GHG Emissions, g CO2eq/MJ
Nitrogen, g/tonne	800.00	3.22
P_2O_5, g/tonne	300.00	0.11
K_2O, g/tonne	1,000.00	0.21
$CaCO_3$, g/tonne	5,200.00	0.71
Herbicide, g/tonne	45.00	0.39
Insecticide, g/tonne	2.50	0.02
Total		4.66

There is a range of fertilizer rates that can be found in the literature. The values used in GREET are within the range and are generally weighted to the more recent data such as the Seabra et al. 2011 report. It is obviously the nitrogen rate that has the largest impact and the earlier version of GREET, such as 1.8d used 1091.7 g/tonne of cane.

It is likely that one of the reasons for a trend to lower nitrogen inputs is the increase in mechanical harvesting and the elimination of the straw burning. This increases the nitrogen in the crop residues that are returned to the soil. The nitrogen content of the residues that are not burned during a mechanical harvest were estimated by Fortes et al (2013) to be 41 kg/ha, or 512 g/tonne at an 80 tonne/ha yield. This is consistent with the reduction N fertilizer seen over the past decade and the reduction in straw burning that accompanies the increase in mechanical harvesting.

The conclusion is that, like the farm energy, it is not appropriate to use the same fertilizer parameters for all four scenarios. There should be different parameters for the manual harvest from the mechanized harvest. The manual harvest should have higher nitrogen inputs than the average values in the model and the mechanized harvest should be lower than the current model value.

2.3 N_2O Emissions

The N_2O emissions in the CA GREET model are fixed at 7.48 g CO_2eq/MJ. None of the user inputs have an impact on this value. There are two factors that have an impact on the calculation: the total quantity of nitrogen applied, and the N_2O emission factor applied. These are discussed below.

2.3.1 Nitrogen Applied

The nitrogen applied is the sum of the synthetic nitrogen fertilizer, nitrogen applied through amendments such as vinasse application, and the above and below ground crop residues. The values in the CA GREET model are listed below.

Table 2-4 Nitrogen Additions to the System

Source	Quantity, g/tonne	CO_2eq Emissions, g/MJ
Synthetic Fertilizer	800	2.88
Crop Residue	1,036	3.73
Filtercake	36	0.13
Vinasse	205	0.74
Total	2,077	7.48

In the CA GREET model the crop residue value is independent of the type of harvest. The model assumes that the nitrogen in the crop residue is returned to the soil as ash. However the data on the fertilizer that is applied does not appear to support this. If the nitrogen in the burned residue is returned to the soil it is not likely returned to the sugarcane field but at some other land.

The proportion of nitrogen from fertilizer and from crop residue should vary depending on whether or not there is straw burning.

2.3.2 N_2O Emission Factor

The model uses the basic IPCC Tier 1 emission factors for the synthetic nitrogen and the crop residues. This includes the direct emissions of N_2O from nitrogen and crops residues, the emissions from nitrogen that is leached from the site and run-off, and the emissions from volatilization of some of the applied nitrogen. This is a misapplication of the IPCC methodology as there should be a small difference between the emission factor for crop residues, which have no volatilization impact and the synthetic fertilizer which does have a volatilization factor. If the factor for synthetic nitrogen is 1.325%, the value for the crop residue should be 1.225%. The 1.325% is made up of:

- 1% of the nitrogen in the synthetic nitrogen and crop residues is emitted as N_2O (EF1).
- 10% of the synthetic nitrogen is volatilized and 1% of that is emitted as N_2O.
- 30% of the N applied is leached or run-off and 0.75% of that is emitted as N_2O.
- Total is 1% + 0.1*1% + 0.3*.075% = 1.325%

The larger issue is whether or not the IPCC Tier 1 default value for EF1 of 1% is appropriate for this region of the world. N_2O emissions are influenced by soil type, precipitation, topography, temperature, and other factors. The GREET model has applied some different factors for different crops but the CA GREET model has applied the same factors for all crops. This will result in underestimating the emissions for some crops and overestimating the emissions for other crops.

2.3.2.1 The Scientific Literature

Sugarcane has a high need for moisture and there is evidence that the N_2O emission factor should be higher due to high levels of precipitation. Renouf et al (2010), in a study of Australian sugarcane production, use an average value of 0.04 for EF1 and report a range of 0.01 to 0.07. Thorburn et al (2010) modeled the N_2O emissions from sugarcane production systems in Australia and determined a range of N_2O emissions form 3-5% of fertilizer applied. Denmard et al (2010) measured N_2O emissions at two sites in Australia and found a range of emissions from 2.8 to 21% of nitrogen in applied fertilizer. The Australian national GHG inventory applies a value of 1.25% for EF1 but it is not clear if this is a Tier 2 value, or simply the Tier 1 value from the 1995 guidelines.

Lisboa et al (2011) looked at this issue for sugarcane production. In addition to the data from Australia they also found data for Hawaii. They determined that the average N_2O emission rate was 3.87%, however while they compare this value to the IPCC EF1 value, they are not comparable. The 3.87% is the total N_2O emissions based just on the nitrogen applied with synthetic fertilizer. It does not include the nitrogen applied from residue or other sources, nor does it include the N_2O from nitrogen leached from the site. Including these would lower the emission factor.

Although information on N_2O emissions for Brazilian sugar cane production is more limited a recent paper by Walter et al. (2014) reported:

> *Experiments in Australia comparing burnt and unburnt harvesting systems indicate that the maintenance of sugarcane straw on the field increases soil N_2O. These results have been recently corroborated by field experiments conducted in Brazil, but with an even more marked increase when vinasse is applied. Because the soil–atmosphere exchange of N_2O depends on complex interactions, more regional and site-specific data are needed to evaluate the impact of this source on the overall GHG balance of biofuels.*

Signor et al (2013) measured the N_2O emissions from sugar cane production at two sites in Brazil. At the first site the proportion of N lost as N_2O ranged from 0.80 to 12.95%. At the second site N_2O emissions varied from 1.22 to 1.53% of added N for ammonium nitrate treatments and from 0.31 to 1.10% for urea.

Experiments reported by da Silva Paredes (2014) found the highest proportions of N emitted as N_2O were registered in the vinasse treatment, which amounted to 15 % of the N applied in the first greenhouse experiment, and 2.5 % in the field experiment, however the N_2O emission rate for just urea were considerably below the Tier 1 default value of 1%.

Vargas et al (2014) investigated the impact of soil moisture and the level of trash retained in the soil and found that N_2O emissions increase with soil moisture and the presence of trash on the soil doubled the impact of increasing soil moisture on N_2O emissions.

Although there is significant uncertainty with respect to the N_2O emission factor for sugar cane production in Brazil, the scientific literature indicates that rates are higher when the fields are not burned and the trash remains on the field. Rates are also higher when vinasse is applied to the field. More work has been done in Australia and corroborated with field experiments in Brazil, and all of that work suggests that the appropriate emission factor is greater than the 1% value for EF1 that has been used by CARB.

2.4 SUGAR CANE FARMING SUMMARY

The CA GREET model does not apply different energy use factors to sugar cane farming even though the two scenarios with mechanical harvesting require almost twice the energy of a manual harvest system. A mechanical harvest system with 100% of the energy supplied by diesel fuel will have GHG emissions of 7.54 g CO_2eq/MJ.

There is evidence that the crop residues that are left on the field are reducing the synthetic nitrogen that is required. The proportion of nitrogen from fertilizer and from crop residue should vary depending on whether or not there is straw burning. The CA GREET model is assuming that there is no difference in nitrogen requirements between burned and unburned fields, an unlikely scenario.

Although there is significant uncertainty regarding the appropriate N_2O emission factor for sugar cane production, the best information in the peer reviewed literature indicates that the 1% EF1 factor used by CARB is too low. The impact of increasing this to 1.5% is an increase in sugar cane N_2O emissions of 2.83 g CO_2eq/MJ.

3. STRAW BURNING

For fields that are not mechanically harvested the CA GREET model assumes that the fields are burned prior to harvesting. This does result in different values for the manual versus mechanical harvested scenarios, where a credit for the burning emissions is introduced in the mechanical harvesting systems.

In the GREET model all of the nitrogen in the straw is included in the crop residue whether the straw is burned or is left on the soil. This is not likely to be the case but correcting it would result in lower emissions for fields that are burned and no change in the emissions for mechanical harvesting.

Even though the straw is biogenic the methane emissions and the N_2O emissions must still be included in the calculations of GHG emissions. The emission factors used in GREET are shown in the following table.

Table 3-1 Straw Emission Factors

	CA GREET	IPCC Grassland	IPCC Ag residue
	g/tonne		
Methane	2,700	2,300	2,700
N_2O	7	21	7

CA GREET also converts the CO and VOC emissions to CO_2eq for straw burning and then provides a credit for the carbon uptake from the atmosphere. This essentially uses the biogenic methane GWP factor of 22.25.

The IPCC values shown above are for grassland burning and for Ag residue burning, as there are no specific emission factors for sugarcane field burning. The source of the IPCC estimates is the paper by Andrea & Merlet (2001). In that paper there are over 40 references to support the grassland estimates and the note beside the Ag residue value is “Value is a best guess”.

The GHG emissions for straw burning would increase to 14.42 g CO_2eq/MJ if the IPCC Grassland values were used rather than the Ag residue values.

3.1 STRAW BURNING SUMMARY

The straw burning emissions are too low by about 4.43 g CO_2eq/MJ as a result of using the IPCC emission factors for Ag residue burning rather than the values for grassland and savanna burning. This increase would be reduced to about 2.5 g CO_2eq/MJ if the nitrogen from the burned straw was not returned to the soil as discussed in the previous section.

4. CANE TRANSPORTATION

The cane transportation distance is a user input to the CA GREET model. They have modelled both a medium duty and a heavy duty truck. This is appropriate because both types of trucks can be used, although they have assigned a 100% share to both types and the share is not a user input. Either one or the other will be used, not both. The share should also be a user input.

The same energy use is used for HD and MD trucks for all pathways in the model. Sugar cane transport it usually at lower speeds than highway travel in North America but the roads are generally dirt, so the assumption of the same energy use is probably reasonable.

The transportation distance is the user input and it is the key parameter in driving the GHG emissions.

4.1 CANE TRANSPORT SUMMARY

The model should be changed so that the share of the delivery of cane by medium duty trucks and by heavy duty trucks is a user input. The truck energy requirements are the same as for corn ethanol.

5. ETHANOL PLANT

The GHG emissions from the ethanol plant stage using the default values in the CA-GREET model amount to 2.30 g CO_2eq/MJ, or less than 10% of the lifecycle emissions for each of the 4 scenarios. The composition of the total is discussed below.

5.1 ENERGY USE

The T1 Calculator sheet asks for total energy use in the mill by type of energy. The calculator as produced only includes some residual oil use and some electric power use. It has zero for biomass use. All of the 2.30 g CO_2eq/J of emissions are energy derived.

Sugar cane mills burn a lot of bagasse to provide the power and the steam for the mills. This biomass is hardcoded into the model and is not adjusted when a user enters biomass energy into the T1 Calculator sheet. It is also not included in the energy consumption values. If a mill imported bagasse or straw to produce more electricity, the model will not produce higher emissions as a result of the higher biomass inputs.

The contribution of the default energy values to the total for this stage is shown in the following table. Even though the bagasse is biogenic the methane and N_2O emissions are still included in the calculations.

Table 5-1 Ethanol Plant Energy Related Emissions

Type	Value	Emissions
	BTU/gal	G CO_2eq/MJ
Residual oil (10% loss of lubricants)	300	0.04
Power	24.37	0.00
Bagasse	89,272	2.26
Total	89,596.37	2.30

Most of the emissions are related to methane and N_2O emissions from burning the bagasse. It is not clear on the T1 Calculator sheet that the residual oil use is related to lubricants and users will likely try and zero this value out when they use the calculator.

5.2 CHEMICALS

The two chemicals that are included in the T1 Calculator sheet are sulphuric acid and ammonia. Both are zero in the model. Seabra (2011) reports sulphuric acid consumption in the mills of 0.0074 kg/litre, 28 g/gal. The model is broken as it transfers the 28 g of sulphuric acid to cell DU 357 (Alpha Amylase) on the EtOH sheet rather than to DU 361 (Sulphuric Acid). This results in GHG emissions of 169,460 g CO_2eq/MJ for the ethanol production stage, an obvious error. The ammonia also goes to the wrong cell on the EtOH sheet.

The CA GREET model for Tier I applications doesn't apply to mills that produce sugar and ethanol. These need to be done using the Tier 2 methodology, but are still expected to be done using the CA GREET model as the base. These mills use some lime in the production process (Seabra reports 42.6 g/gal). There is no provision in CA GREET for including lime as an input to the ethanol production process. This needs to be added as user input. Lime has GHG emissions of about 1.25 g/g CAO so including this chemical would add about 0.7g CO_2/MJ to the ethanol production emissions.

5.3 POWER EXPORTS

The new CA-GREET model is using the average power mixes rather than trying to estimate the marginal power in all of the different regions that are included in the model. In the case of Brazil, this drastically lowers the credit for power exports.

There is an error in the CA-GREET model with respect to the Brazilian power mix. When the data is migrated from the T1 Calculator sheet to the ETOH sheet the values for nuclear and biomass power are transposed. The values in cells Q293 and Q294 on the ETOH sheet are therefore incorrect and lead to a slightly higher credit (~0.1 g/MJ) than should be calculated.

A larger issue is the quality of the data being used in the model for Brazil power. The power mix for Brazil that is used in CA-GREET is shown in the following table. The source identified for the data is the US DOE EIA country brief. This brief was updated in December 2014 and the results are also shown in the table. Small amounts from wind, solar, and nuclear made up the rest.

Table 5-2 GREET Brazil Power Mix

	Brazilian Mix in Model	Updated EIA Brief
Resid Oil/Fossil fuels	0.00%	4%
Natural gas	11.00%	11%
Coal	0.00%	0%
Nuclear power	2.00%	0%
Biomass	7.00%	8%
Hydroelectric	55.76%	71%
Geothermal	3.33%	0%
Wind	20.65%	0%
Solar PV	0.26%	0%
Others (purchased)	0.01%	0%
Total	100.01%	94.00%

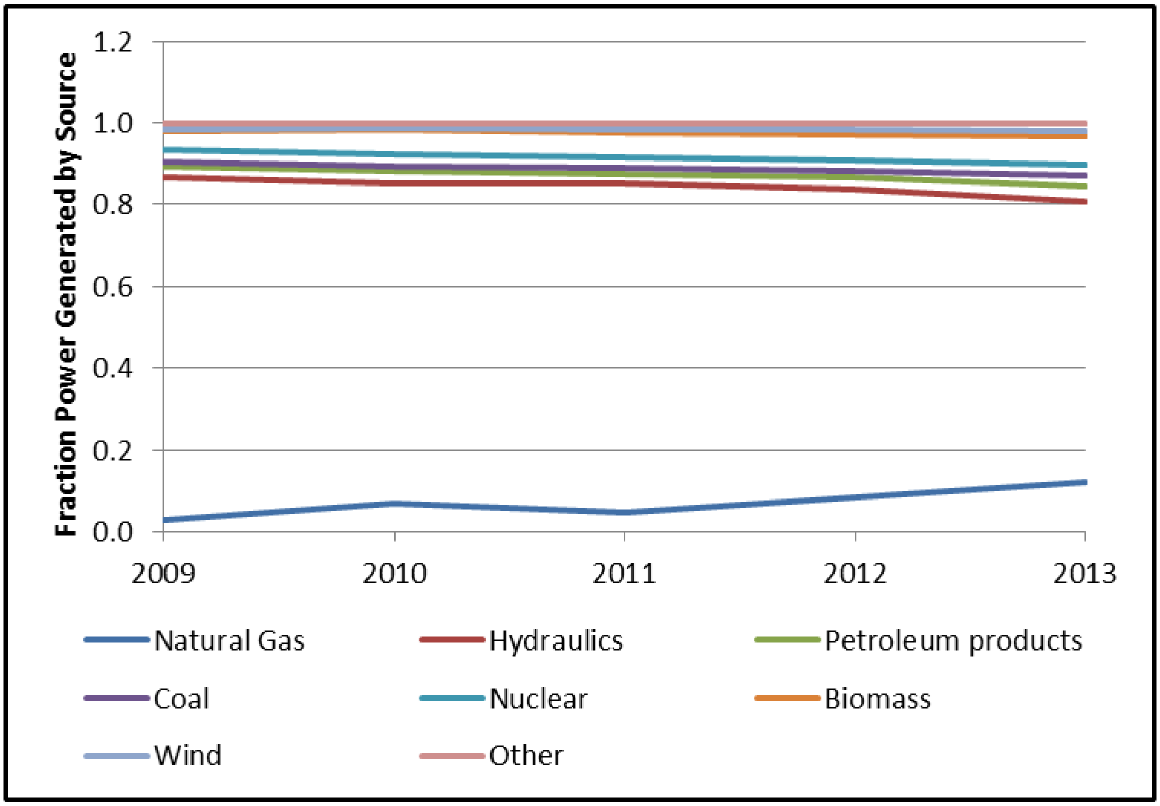
There is a better source of electrical power generation in Brazil. The Energy Research Company - EPE publishes a Statistical Review of the Electric Sector (EPE, 2014). The information from that source is shown below.

Table 5-3 Actual Brazil Power Mix

	2009	2010	2011	2012	2013
Natural Gas	2.86%	7.07%	4.72%	8.46%	12.11%
Hydro	83.87%	78.19%	80.55%	75.18%	68.59%
Petroleum products	2.73%	2.76%	2.30%	2.93%	3.88%
Coal	1.16%	1.36%	1.22%	1.52%	2.60%
Nuclear	2.78%	2.82%	2.94%	2.90%	2.57%
Biomass	4.69%	6.05%	5.95%	6.27%	6.96%
Wind	0.27%	0.42%	0.51%	0.91%	1.15%
Other	1.64%	1.34%	1.81%	1.81%	2.15%
Total	100.00%	100.00%	100.00%	100.00%	100.00%

CARB underestimates the natural gas, coal, and oil used for power generation in Brazil. Furthermore the quantity of gas being used is increasing with time as shown below. The fossil fuel fraction has increased 275% since 2009.

Figure 5-1 Power Generation Trends



Using a more accurate estimate of the Brazilian power mix will slightly increase the base emissions but also increase the power credit available for plants that export power to the grid.

5.4 ETHANOL PRODUCTION SUMMARY

There are several errors in the CA GREET model related to the transfer of information from the T1 Calculator sheet to the core of the model. These include:

1. Nuclear and biomass power shares of the power generation are transposed when they are transferred to the ETOH sheet.
2. The inputs for sulphuric acid and ammonia are input into the cells for enzymes when they move from the T1 Calculator sheet to the ETOH sheet. Entering non-zero values will produce extremely high and erroneous GHG emissions.

There is also the potential for misinterpretation of the input values. The input for Residual oil is really the quantity of used lubricants that are burned in the plant and not the input of residual oil.

The quantity of biomass that is burned at the plants is hard coded in the model. Not all mills burn all of the bagasse on site; some sell a portion to other local industries. The emissions for these operations will be overestimated. The biomass from the T1 Calculator sheet is transferred to the ETOH sheet, but once it goes there it is not included in any calculations. Proper modelling should require the mills to enter the bagasse consumed and not hard code those quantities. The current model would underestimate the emissions from mills that imported bagasse from another facility or used some straw from the fields to produce more electric power for export.

6. ETHANOL TRANSPORTATION

Ethanol can be transported from Brazil to California by truck, rail, and pipeline in Brazil, by ocean tanker, and then by truck in California. In CA-GREET the user will select the transportation distances and the distances for each mode on the T1 Calculator sheet. The values in the calculator create emissions of 7.16 g CO_2e/MJ with only the Brazilian truck, ocean freight and the California Port to blending stations being non-zero inputs. The distance from the blending point to the service station is a non-adjustable system input for all types of ethanol; however the distance is different for sugarcane ethanol compared to corn ethanol (50 miles vs. 40 miles). They should be the same.

Table 6-1 Transportation Emissions

Mode	Distance	Emissions
Brazil Truck	130	1.01
Ocean Ship	8,758	5.06
US Truck	90	0.70
Truck to Service Station	50	0.39
Total		7.16

The Brazilian trucking distance is short but that will have to be filled in by the applicant for the specific mill.

The issue for modelling is the calculation of the ocean shipping emissions. There are three issues with the calculation which lead to an inaccurate assessment of the emissions. These are described below.

6.1 BACKHAUL

All of the ocean movements in the CA GREET model, ***except Brazilian ethanol***, have an energy charge for the primary movement and the backhaul movement. This backhaul charge is 84% of the energy of the one-way movement. There is no backhaul charge for the Brazilian ethanol. If there was, the emissions would increase by 3.43 g/MJ. The model should be revised to include backhaul as a default value whenever an applicant cannot prove that there will be no backhaul for the relevant pathway.

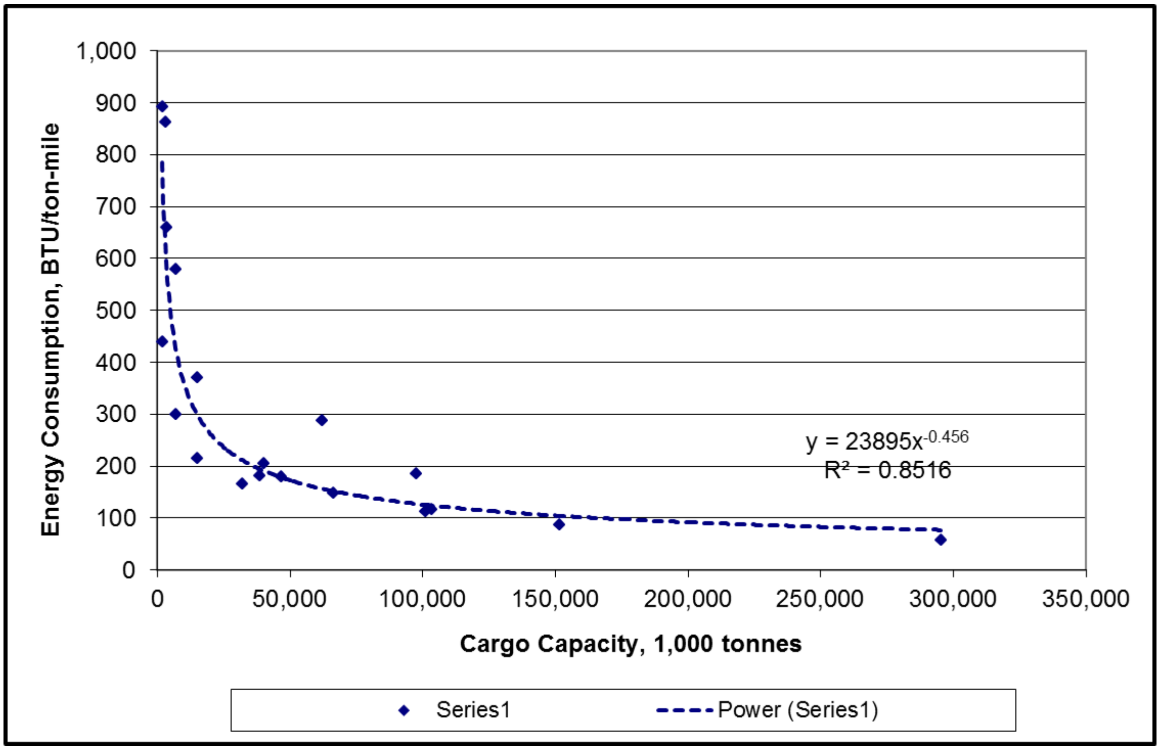
6.2 SHIPMENT SIZE

The CA GREET model assumes that the ethanol is delivered in 22,000 tons shipments. The US DOE EIA reports petroleum product imports on a company level basis. The 2014 data for the first 10 months of the year is currently available. Sugarcane ethanol from Brazil, Guatemala, and Nicaragua has been received in the US. No Brazilian ethanol has been landed in California during this time period. The average size of the shipment was 11,200 tons. This includes shipments that were delivered to more than one port as a single load of the combined capacity. This is only half of the value in the model and it will result in the energy and thus the emissions being underestimated. The model should be revised to require a verifiable shipment size as a user input.

6.3 Vessel Energy Requirements

The size of the ship has a large impact on the energy expended; larger ships require less energy to move the cargo. The International Maritime Organization (IMO, 2008) published data on the GHG emissions for various sizes of ships. The GHG emissions are easily converted to energy and the relationship for a range of chemical, petroleum product, and crude oil carriers are shown in the following figure. The energy consumption is very sensitive to vessel size, especially for the small vessels, and the energy can increase by 50% of more moving from a 22,000 ton vessel to an 11,000 ton vessel.

Figure 6-1 Energy Requirements vs. Vessel Size



The energy use for the 22,000 ton shipment in GREET is 140 BTU/ton-mile and it excludes the backhaul. The IMO estimate for an 11,000 ton shipment is 343 BTU/ton-mile. To this would be added the 84% for a back haul, for a total energy use of 631 BTU/ton-mile or 4.5 times more than the CA GREET model estimates. This would add about 17.5 g/MJ to the Brazilian sugarcane ethanol carbon intensity for pathways that cannot verify that there is no backhaul.

The calculation of energy consumption in GREET is based on theoretical calculations, includes some erroneous correlations, and underestimates the real world energy use. For example, the faster a ship travels the more power is consumed, but in GREET the energy consumption decreases with faster travel. This is because the power requirements increase as the cube of the velocity in the real world but in GREET the power requirements are independent of the speed. The energy consumed per mile is a function of the square of the speed, or power divided by speed. GREET uses the power/speed equation but doesn't account for the power being a function of the speed, so the end calculated result is incorrect. The model must be revised to correct the errors.

6.4 TRANSPORTATION SUMMARY

There are significant issues with the ocean shipping calculations in GREET for many of the fuels, including sugarcane ethanol. The issues for sugar cane ethanol include:

1. The shipment size of 22,000 tons is too high and is not a user input.
2. Sugar cane Ethanol from Brazil, uniquely of all of the fuels in CA GREET, is not charged with a backhaul.
3. The energy use for ocean shipping is calculated but the calculations underestimate the energy used by a significant amount.
4. Energy use in the model is 145 BTU/ton-mile. Data from the IMO suggests that this should be 335 BTU/ton-mile plus 283 BTU/ton-mile for the backhaul. This would increase the ocean shipping emissions by 17.0 g CO_2eq/MJ, a very significant difference.

7. DISCUSSION

The sugar cane ethanol pathway in the new CA GREET 2.0 model has been thoroughly reviewed. The review has considered the following questions.

- Are the pathways consistent?
- Does the model ask for the key input parameters?
- Does the model reflect the actual practices?
- Does the model have the correct background data and are the calculations correct?

A significant number of issues were identified. Most of the issues results in the model returning values that are lower than what would be returned if the issues were addressed properly.

7.1 SUGAR CANE FARMING SUMMARY

The CA GREET model does not apply different energy use factor to sugar cane farming even though the two scenarios with mechanical harvesting require almost twice the energy of a manual harvest system. A mechanical harvest system with 100% of the energy supplied by diesel fuel will have GHG emissions of 7.54 g CO_2eq/MJ.

There is evidence that the crop residues that are left on the field are reducing the synthetic nitrogen that is required. The proportion of nitrogen from fertilizer and from crop residue should vary depending on whether or not there is straw burning. The CA GREET model is assuming that there is no difference in nitrogen requirements between burned and unburned fields, an unlikely scenario.

Although there is significant uncertainty regarding the appropriate N_2O emission factor for sugar cane production, the best information in the peer reviewed literature indicates that the 1% EF1 factor used by CARB is too low. The impact of increasing this to 1.5% is an increase in sugar cane N_2O emissions of 2.83 g CO_2eq/MJ.

7.2 STRAW BURNING SUMMARY

The straw burning emissions are too low by about 4.36 g CO_2eq/MJ as a result of using the IPCC emission factors for Ag residue burning rather than the values for grassland and savanna burning. This increase would be reduced to about 2.5 g CO_2eq/MJ if the nitrogen from the burned straw was not returned to the soil as discussed in the previous section.

7.3 CANE TRANSPORT SUMMARY

The model should be changed so that the share of the delivery of cane by medium duty trucks and by heavy duty trucks is a user input. The truck energy requirements are the same as for corn ethanol.

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There is also the potential for misinterpretation of the input values. The input for Residual oil is really the quantity of used lubricants that are burned in the plant and not the input of residual oil.

The quantity of biomass that is burned at the plants is hard coded in the model. Not all mills burn all of the bagasse on site; some sell a portion to other local industries (San Martinho, 2007). The emissions for these operations will be overestimated. The biomass from the T1 Calculator sheet is transferred to the ETOH sheet, but once it goes there it is not included in any calculations. A proper modelling would require the mills to enter the bagasse consumed and not hard code those quantities. The current model would underestimate the emissions from mills that imported bagasse from another facility or used some straw from the fields to produce more electric power for export.

7.5 TRANSPORTATION SUMMARY

There are issues with the ocean shipping calculations in GREET for many of the fuels, including sugarcane ethanol. The issues for sugar cane ethanol include:

1. The shipment size of 22,000 tons is too high and is not a user input.
2. Ethanol, uniquely of all of the fuels in CA GREET, is not charged with a backhaul.
3. The energy use for ocean shipping is calculated but the calculations underestimate the energy used by a significant amount.
4. Energy use in the model is 145 BTU/ton-mile. Data from the IMO suggests that this should be 335 BTU/ton-mile plus 283 BTU/ton-mile for the backhaul. This would increase the ocean shipping emissions by 17.0 g CO_2eq/MJ, a very significant difference.

7.6 SUMMARY

With respect to the four questions that were investigated we find that:

1. There are inconsistencies between some aspects of the sugarcane ethanol pathway and all other pathways.
2. There are key input parameters that should be included in the model. These would include, the share of cane transported by MD and HD trucks, the ocean shipment size, and confirming that a backhaul is always provided.
3. The model does not reflect actual practice. The lack of change in the farming emissions with the different practices that are employed is problematic. The ocean shipping size is double the typical shipments.
4. The background data in the model is not accurate. The biggest issue is with the energy used for ocean shipping but the emission factor applied to cane burning should be changed.

In addition, there are some programming errors in the calculator that need to be adjusted. Correcting the issues in the model will increase the GHG emissions in the different scenarios. The following two tables itemize the changes that should be made to the model.

Table 7-1 Summary of Changes - Farming

Stage	Manual Harvest			Mechanical Harvest		
	Default	Revised	Change	Default	Revised	Change
All Diesel	4.65	5.39	0.74	4.65	5.39	0.74
Extra Diesel for Mech Harvest					7.54	2.15
Extra N Fert for manual	3.22	4.43	1.21			
N_2O from extra N	2.88	3.96	1.08			
Total			3.03			2.89

Table 7-2 Changes to Rest of Pathway

Item	Default	Revised	Change
N_2O EF	7.48	10.31	2.83
Residue Leaching		7.13	-0.35
Straw Burning EF	10.06	14.42	4.36
Power Export	-0.72	-0.76	-0.04
Shipping			
Backhaul	7.16	11.41	4.25
Ship size		18.88	7.47
IMO Energy		24.15	5.27
Total			23.79

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Appendix D

Appendix D

Compliance with the Revised LCFS Program and Associated Economic Impacts

Prepared by Edgeworth Economics

CARB's proposed changes in the LCFS regulation call for a reduction in the carbon intensity (CI) of gasoline relative to the baseline level of 99.18 by 2 percent in 2016, 5 percent in 2018, and 10 percent in 2020.[1] In theory, the strategies to achieve those reductions could include 1) displacing gasoline usage with other types of fuel with lower CI values (*e.g.*, electricity); 2) changing the current limit on the percentage of ethanol that can be blended into California gasoline below the E85 level (which is E10); 3) reducing the average CI of renewable fuel blended with gasoline under the E10 limit; and 4) deployment of credits generated from the use of renewable fuels prior to 2016 and the use of renewable fuels in diesel after 2016. CARB projects that compliance with the LCFS will rely significantly on the third method through at least 2020.[2] This Appendix to Growth Energy's comments identifies the circumstances under which the LCFS program will shift the supply of ethanol for the California market from the United States to Brazil, as a result of strategies to reduce the average CI of renewable fuels blended into gasoline under the E10 limit.

Through 2020, CARB has projected that compliance with the LCFS could be reached primarily through a shift from corn ethanol, now largely sourced from the Midwest[3] with an average CI value of about 82, to cane ethanol from Brazil, which currently has an average CI value of about 72.[4] CARB developed an "illustrative compliance scenario" which projects a reduction in corn ethanol use in California gasoline from the current (2014) level of 1,250 million gallons per year to 700 million gallons per year in 2020, with an increase in consumption of cane ethanol equal to about 64 percent of that reduction. Thus, CARB's scenario would

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[1] CARB, *Staff Report: Initial Statement of Reasons for Proposed Rulemaking*, December 2014 ("ISOR"), p. ES-3.
[2] ISOR, p. B-39.
[3] The Renewable Fuels Association (RFA) lists three operating corn ethanol plants in California, with total capacity of 175 million gallons per year, representing about one percent of total U.S. ethanol production and about 14 percent of consumption in California. [RFA website at www.ethanolrfa.org/bio-refinery-locations]
[4] ISOR, p. B-39.

involve a reduction in consumption of Midwest-sourced corn ethanol of about 550 million gallons per year as of 2020, relative to today, equivalent to the entire output of about seven typical-sized ethanol plants.[5]

CARB presents the foregoing scenario as an example of how compliance could be achieved. CARB bases its analysis of the economic impacts of the LCFS on an assumption that credit prices would equal $100 from 2016 through 2020.[6] CARB also evaluates economic-impact scenarios based on assumed credit prices of $25, the current value as of January 2015, and $57, the average value from 2012 to 2013.[7]

To determine whether credit prices at those levels would, in fact, cause fuel marketers in California to switch from Midwest-based corn ethanol to Brazilian cane ethanol, Edgeworth Economics prepared an analysis of the total, delivered cost of both fuels under various assumptions about the CI for each type. Our analysis uses the following data:

- A CI range for Midwest-based corn ethanol of 81.4 to 92.4, representing a range of ratings for ethanol refineries located in the Iowa/South Dakota/Minnesota area that currently ship product to California, based on CARB's list of "Approved Physical Pathways" and information provided by Growth Energy members.
- A CI range for Brazilian cane ethanol of 72.5 (current) to 40 (as of 2016), as reported in the ISOR at p. B-39.
- Ethanol spot prices at Chicago, IL and Santos, Brazil—2014 average [source: Platts] and 2016 forecast [source: OECD-FAO, *Agricultural Outlook 2014-2023*].
- Rail freight rates from Midwest refinery locations to California, provided by Growth Energy members.
- Maritime freight rates from Brazil to California, including tariff and terminal charge [source: Odin Marine Group, *Ethanol Report*, January 2015 and Growth Energy members].

[5] The average output of operating ethanol facilities is about 76 million gallons of ethanol per year. [RFA website at www.ethanolrfa.org/pages/statistics]
[6] ISOR, p. VII-1.
[7] ISOR, pp. VII-1-2 and "Monthly LCFS Credit Transfer Activity Report for January 2015" [CARB website at www.arb.ca.gov/fuels/lcfs/credit/20150210_jancreditreport.pdf]

- D5 and D6 Renewable Identification Number (RIN) prices—2014 average [source: OPIS].

Because the delivered cost of Brazilian ethanol in California is substantially higher than the cost of Midwest corn ethanol at present, with LCFS credit levels around $25, relatively little cane ethanol is imported into California[8], while Midwest facilities with CI ratings in the low 90s continue to deliver product. At the average ethanol and RIN prices experienced in 2014, the value of an LCFS credit would need to rise to $156 in order to incentivize a switch from the highest-CI-rated Midwest sources to Brazil. The spread between prices for conventional (D6) RINs and advanced biofuel (D5) RINs has recently expanded, which provides additional incentive to import cane ethanol from Brazil. Based on the average spread in January 2015, an LCFS credit price of $105 would incentivize the same switch.

However, based on forecasts for ethanol prices in 2016, which show a narrowing of the price differential between U.S. and Brazilian ethanol, an LCFS credit price of about $36 (based on 2014 RIN spreads) would cause a switch from 92.4-CI corn ethanol to cane ethanol; and a credit price of only $77 would cause a switch from 81.4-CI corn ethanol to cane ethanol. These figures are well below CARB's estimate for LCFS credit prices of $100 in 2016.

If Brazilian cane ethanol can receive the CI ratings predicted by CARB, then the switch will occur at even lower credit prices. For example, CARB projects that Brazilian ethanol will have an average CI rating of 40.0 by 2016.[9] At that rating, LCFS credit prices as low as $14 would result in a switch away from the higher-rated facilities in the Midwest, and credit prices as low as $17 would result in a switch away from even the lower-rated Midwest facilities.[10] In this scenario, even Midwest facilities with CI ratings as low as 70, which CARB claims will be the average rating of the Midwest corn facilities still delivering product to California as of 2016[11], would be at risk. Credit prices as low as $23 would be sufficient to induce a switch to imported cane ethanol. CARB's scenario indicating a substantial decline in the use of Midwest corn ethanol in California and an increase in the use of imported cane ethanol is therefore not only

[8] CARB estimates 100 million gallons in 2014. [ISOR, p. B-39]
[9] ISOR, p. B-39.
[10] These figures are calculated using the 2016 forecast for ethanol prices and current RIN spreads.
[11] ISOR, p. B-39.

plausible, but probable if sufficient ethanol is available from Brazil, even at modest credit prices well below CARB's projected level of $100.[12]

The implications for Midwest ethanol producers in this scenario would be severe. Assuming that U.S.-wide demand for ethanol does not increase (the Energy Information Administration projects ethanol consumption will be flat through 2016[13]), then the increased imports of Brazilian ethanol would result in some combination of 1) lost production or shut-down of Midwest facilities—with total lost volumes equivalent to as many as approximately seven typical-sized plants by 2020, as noted above; or, at a minimum, 2) increased logistics costs associated with exporting corn ethanol to the nearest source of demand outside the U.S., which could be Brazil. Obviously, the latter outcome would not result in a decrease in world-wide carbon emissions.

The economic impact of reduced production levels or complete plant closures in the Midwest can be estimated based on the characteristics of typical ethanol refineries. On average, U.S. corn ethanol facilities employ approximately 0.8 employees per million gallons of ethanol produced, or about 61 employees for a typical plant.[14] A reduction in ethanol demand of 550 million gallons per year therefore would result in a direct loss of approximately 440 jobs at ethanol refineries. In addition to these direct effects, the regions that host ethanol production facilities would experience additional reductions in economic activity stemming from reduced purchases of locally-sourced inputs (the "indirect" impact) and reduced spending by facility employees and local vendors (the "induced" impact). These additional economic impacts are generated by the "multiplier" effect, which results from the recycling of business revenues and household income within the local region. Plausible estimates for the overall multiplier effect for employment applicable to the ethanol industry range from about 2 (indicating a total impact

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[12] This result holds even if the price differential between U.S. and Brazilian ethanol remains closer to current levels, rather than declining as indicated in the forecast described above.

[13] U.S. Energy Information Administration, *Short-Term Energy Outlook*, February 10, 2015.

[14] Based on various sources, including: John Urbanchuk, "Contribution of the Ethanol Industry to the Economy of the United States," Cardno ENTRIX, prepared for the Renewable Fuels Association, February 2, 2012; David Swenson, "Understanding Biofuels Economic Impact Claims," Iowa State University, April 2007; and various public SEC filings.

on employment equal to two times the direct employment impact) to about 7.[15] Applying a figure of 4 to the direct employment impacts calculated above implies a loss of approximately 1,760 jobs in ethanol producing regions.

Even assuming that the facilities forced out of the California market could find customers outside the U.S., there would still be substantial costs to the industry. For example, transport of ethanol from the Midwest to Brazil would entail increased logistics costs of approximately 10 cents per gallon[16], or $55 million per year, assuming sufficient demand in Brazil for all 550 million gallons of displaced corn ethanol.

[15] See, for example, Urbanchuk, February 2, 2012, *op. cit.*; Swenson, April 2007, *op. cit.*; Susan Christopherson and Zachary Sivertsen, "Economic Policy Makers Beware: Estimating the Job Impact of Public Investment in Biofuel Plants," working paper, Cornell University, December 12, 2009; and Dave Swenson, "Input-Outrageous: The Economic Impacts of Modern Biofuels Production," Iowa State University, June 2006.

[16] Based on the sources described above.

Appendix E

Nos. 12-15131, 12-15135

UNITED STATES COURT OF APPEALS FOR THE NINTH CIRCUIT

ROCKY MOUNTAIN FARMERS UNION, *et al.*, Plaintiffs-Appellees,

v.

JAMES N. GOLDSTENE, *et al.*,Defendants-Appellants, and ENVIRONMENTAL DEFENSE FUND, *et al*.,Intervenor-Defendants-Appellants.

Appeal from the United States District Court for the Eastern District of California (D.C. Nos. 1:09-cv-02234-LJO-GSA, 1:10-cv-0013-LJO-DLB)

DECLARATION OF ERIN HEUPEL, P.E.

I, Erin Heupel, declare and state as follows:

1. I am the Director of Environment and Technology at POET LLC, a company that constructs and manages ethanol production facilities, headquartered in Sioux Falls, South Dakota. I provide this declaration in support of the opposition by Plaintiffs-Appellees ("Plaintiffs") to the motion filed by Defendants-Appellants ("Defendants") to stay the preliminary injunction and judgments in *Rocky Mountain Farmers Union, et al. v. Goldstene*, Case No. 1:09-cv-02234-

LJO-GSA (E.D. Cal., Dec. 29, 2011).[1] I am a licensed Professional Engineer in the States of Iowa and South Dakota. I make this declaration based on my professional experience and my personal knowledge of the facts set forth herein. I am willing and able to present under oath the facts set forth in this Declaration if called as a witness before the Court.

2. The purpose of this declaration is to respond to statements in the Declaration of Michael Waugh, dated January 20, 2012, and filed in this Court by Defendants on February 10, 2012, on two subjects: (i) the creation of "individualized" pathways for some corn ethanol plants under the California low-carbon fuel standard ("LCFS") regulation, and (ii) the impact of District Court's preliminary injunction on the environmental benefits that Defendants attribute to the LCFS regulation. *See* Declaration of Michael Waugh in Support of Defendants and Defendant-Intervenors' Motion to Stay Preliminary Injunction and Judgments Pending Appeal (Dkt Entry 21-7) ("Waugh Decl.") ¶¶ 5, 39-41, 52-59, *and id.* at 11:9.

3. I am in charge of the efforts of ethanol plants managed by POET LLC, to receive CARB approved individualized carbon intensity "pathways" for

[1] *See* Motion for A Stay of the District Court's Orders and Judgments Pending Appeal (Dkt Entry 22-1) ("Stay Mot.").

the plants managed by POET LLC that can qualify for such pathways.[2] My duties at POET LLC require me to have complete knowledge of the technologies, processes, and methods used for the production of corn ethanol and various co-products by the plants that POET LLC manages, including the production efficiencies and energy requirements of those plants. My responsibilities at POET LLC also require me to have substantial knowledge of the same attributes of corn ethanol plants that compete with the plants that POET LLC manages.

4. At the outset, it is important to understand that companies in the U.S. corn ethanol industry have strong commercial incentives to maximize yield from feedstock and to minimize energy usage, and thus to minimize greenhouse gas ("GHG") emissions. Corn ethanol plants cost millions of dollars to build. Midwest corn ethanol plants are carefully sited in order to have ready access to their feedstock, as well as competitively priced natural gas, electricity, or other sources of energy to run the plant. The companies that survive and prosper in this industry are those whose plants are designed from the beginning for maximum efficiency in feedstock conversion and minimum energy consumption. Next to corn costs, energy costs are the largest variable cost in producing corn ethanol.

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[2] *See* Waugh Decl. ¶¶ 52-56. The plants that POET LLC constructs and/or manages are owned by separate investor groups. *See* Declaration of Robert Whiteman (filed March 1, 2012) at note 3.

5. A number of plants managed by POET LLC have received CARB staff approval for 11 different individualized pathways for corn ethanol. I am personally familiar with the attributes of each plant awarded those pathways that the LCFS regulation treats as relevant in determining the carbon intensity of the ethanol that those plants produce. The relevant plants made no changes in production methods, feedstock, methods of transport, or any other factor relevant to the pathway application, in order to reduce the carbon intensity that would be assigned to ethanol produced at those plants. POET LLC obtained the CARB approved CI pathways for these plants by documenting the attributes of production and energy supply relevant under the LCFS regulation that those plants had adopted for commercial reasons, completely independent of the LCFS regulation and the regulation's requirements for the establishment of alternative pathways.

6. When plants managed by POET LLC make changes in their technologies, production methods, or energy sources, and those changes reduce the carbon intensity, POET LLC seeks changes in the carbon intensity values that apply to those plants to the extent possible under the LCFS regulation. In such instances, however, the motivating factor for the change at the plant is not the LCFS regulation, but the need to remain competitive in production methods and technologies within the Midwest corn ethanol industry. In addition, to my knowledge, none of the Midwest corn ethanol plants that compete with those

managed by POET LLC have made changes in their technologies, production methods, or energy inputs in order to gain a lower carbon intensity value under the LCFS regulation; instead, those plants strive to increase efficiency and reduce energy consumption for the same commercial reasons as the plants managed by POET LLC.

7. The LCFS regulation becomes more stringent in each year after 2011. But, contrary to what appears to be the position taken in Mr. Waugh's declaration, it would not be commercially practicable for Midwest corn ethanol plants to try to keep up with the increases in the stringency of the regulation, simply in order to try to stay in business in California.[3]

8. Under the LCFS regulation, all corn ethanol plants, including those in the Midwest, must add an assigned "indirect" carbon intensity emissions factor of 30 gCO_2eq/MJ to their "direct" carbon intensity emissions factor. The "indirect" emissions factor is more than 40 percent of the total carbon intensity level assigned to the corn ethanol pathway that, according to Mr. Waugh's Declaration, has the lowest carbon intensity level recognized by the CARB staff.[4] Nothing that any

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[3] *See* Waugh Decl. ¶¶ 41, 44.

[4] *See* Waugh Decl., Exh. E at 8 (pathway value of 73.21 gCO_2eq/MJ for Pathway No. ETHC0035). The pathway that Mr. Waugh's declaration identifies as the "lowest carbon intensity value approved for any ethanol," for a plant located in Kansas (Waugh Decl. ¶ 53), is a pathway for a plant that uses the combination of wheat slurry, sorghum, and corn and is not a pathway for an ethanol plant using

single corn ethanol plant or group of corn ethanol plants can do will reduce the "indirect" carbon intensity emissions factor assigned by the LCFS regulation. As a result, the impact of plant changes in improving efficiency or reducing energy consumption do not result in proportional changes in the assigned CI value. For example, the 73.21 gCO_2eq/MJ value above consists of 43.21 gCO_2eq/MJ for the production of feedstock and ethanol as well as ethanol transport and the value of 30 gCO_2eq/MJ for indirect emissions. A 10% reduction in the 43.21 gCO_2eq/MJ value to 38.89 gCO_2eq/MJ yields only a 6% reduction in the overall CI value which becomes 68.89 gCO_2eq/MJ. In addition, within the "direct" emissions factor assigned to a corn ethanol plant, the LCFS regulation attributes a substantial increment to GHG emissions attributed to the cultivation and harvesting of corn (potentially, 35.7 gCO_2eq/MJ). Ethanol plants cannot directly control and document how farmers grow and harvest corn, which the farmers grow not only to

corn. Sufficient quantities of sorghum feedstock are not available to most corn ethanol plants, including those in the northern Great Plains that were built to serve the California market. Although the yields from converting grain sorghum to ethanol can be similar to corn, the yields of sorghum per acre are lower, making sorghum a generally less desirable crop than corn for fertile or irrigated land. Sorghum tends to be grown where the land is too marginal to support a profitable corn crop, or where moisture availability is scarce. As was the case with the fuel-grade ethanol industry prior to the implementation of the LCFS regulation, grain producers will grow crops that make the most profitable use of their land and agricultural inputs.

sell to ethanol plants, but also to other customers, on the best possible commercial terms for the farmers.

9. As indicated above, the lowest CI value for any Midwest corn ethanol pathway is 73.21 gCO_2eq/MJ and the direct CI value for that pathway is 43.21 gCO_2eq/MJ. Assuming that this lowest CI corn ethanol is blended with a gasoline blendstock assigned a carbon intensity value of 95.86 gCO_2eq/MJ (which is the value assigned to an "average" gasoline blend), LCFS compliance could only be achieved with a 15% ethanol blend ("E15") through 2015. In order for LCFS compliance to be achieved with E15 in 2016, the CI of Midwest corn ethanol would have to be reduced to 64.20, and the direct CI value to 34.20. This represents approximately a 21% reduction in the direct CI value from the lowest CI value currently documented. That same ethanol blended at 15% into the same gasoline feedstock would begin to generate deficits for the blender starting in 2017.

10. Experience in 2011 has shown that gasoline blenders in California will quickly try to stop buying and blending ethanol that does not generate a credit against the requirements of the LCFS regulation.[5] Given the "indirect" emissions factor automatically assigned to all corn ethanol plants, and the compliance schedule for LCFS regulation in the near term, even the most efficient Midwest corn ethanol plant currently recognized by the CARB staff would need to reduce

[5] *See* Declaration of James M. Lyons ¶¶ 5-7 .

its direct carbon intensity factor by more than 21% and file the necessary documentation with CARB, in order to continue in the California fuel market for one more year past the current limit of 2015. The costs incurred to reduce the carbon intensity of ethanol from the plant would have to be recovered by the end of 2016 before the gasoline blenders stopped buying that plant's ethanol and moved to an alternative fuel with a lower carbon-intensity level, for example, from Brazil or through the use of the "electricity" pathways in the LCFS regulation.

11. The upshot is that even a very efficient Midwest corn ethanol plant would have to find and implement further efficiencies or energy reduction opportunities not driven by the nationwide market and recover the costs of the necessary changes, over a very short time frame. That is not commercially practicable for corn ethanol plants managed by POET LLC or, I believe, for competitor corn ethanol plants. Rather than incur those costs, U.S. corn ethanol plants will try to compete in markets outside California.

12. In sum, I am aware of no evidence that the LCFS regulation has had any significant impact on the level of GHG emissions from corn ethanol plants located in the Midwest. A stay of the preliminary injunction will not cause the corn ethanol plants managed by POET LLC, or any competitors to those plants with whose operations I am familiar, to reduce the GHG emissions from their

operations relative to current levels. A stay of the preliminary injunction issued by the District Court therefore will not restore or continue any GHG emissions reductions during the pendency of this litigation, simply because the LCFS regulation itself has had no effect on GHG emissions attributable to corn ethanol production, nor would it have any such effect in the near term.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct. Executed on March 1, 2012 at Sioux Falls, South Dakota.

Erin Heupel, P.E.

Nos. 12-15131, 12-15135

UNITED STATES COURT OF APPEALS FOR THE NINTH CIRCUIT

ROCKY MOUNTAIN FARMERS UNION, *et al.*, Plaintiffs-Appellees,

v.

JAMES N. GOLDSTENE, *et al.*, Defendants-Appellants, and ENVIRONMENTAL DEFENSE FUND, *et al*., Intervenor-Defendants-Appellants.

Appeal from the United States District Court for the Eastern District of California (D.C. Nos. 1:09-cv-02234-LJO-GSA, 1:10-cv-0013-LJO-DLB)

DECLARATION OF ROBERT WHITEMAN

I, Robert Whiteman, declare and state as follows:

1. I am the Chief Financial Officer of POET Ethanol Products, LLC, d/b/a POET Ethanol Products (hereinafter "POET Ethanol Products"), a company based in Wichita, Kansas, that markets ethanol. I provide this declaration in support of the opposition by Plaintiffs-Appellees ("Plaintiffs") to the motion filed by Defendants-Appellants ("Defendants") to stay the preliminary injunction and judgments in *Rocky Mountain Farmers Union, et al. v. Goldstene*, Case No. 1:09-

cv-02234-LJO-GSA (E.D. Cal., Dec. 29, 2011).[1] I am willing and able to present under oath the facts set forth in this declaration if called as a witness before the Court.

Summary

2. In their stay motion, Defendants claim that the low-carbon fuel standard ("LCFS") regulation has had no adverse impact on what Defendants call the "domestic ethanol industry." (Stay Mot. at 31.) As explained below in the main portion of this Declaration, the U.S. corn ethanol "industry" is compromised of numerous separately-owned corn ethanol production plants, mainly located outside California near the sources of corn used to make ethanol. Long before adoption of the LCFS regulation, investors built ethanol plants in the western Great Plains area of the Midwest to serve the California market. They did so in order to obtain the "California premium" - higher prices that prevailed for corn ethanol in California, compared to other large U.S. markets, resulting from specific economic conditions in California. (*See* ¶¶ __-__ below.) The principal impact of the LCFS regulation within what Defendants define as the "domestic ethanol industry" has fallen on those Midwest producers, who served the California market before the LCFS was adopted.

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[1] *See* Motion for A Stay of the District Court's Orders and Judgments Pending Appeal (Dkt Entry 22-1) ("Stay Mot.").

3. In its first year of implementation, the LCFS regulation forced the exit from the California market of some of those Midwest corn ethanol plants that had been built to serve California. The LCFS regulation also curtailed sales of corn ethanol by some other Midwest plants that had previously had significant sales of ethanol in California. (*See* ¶¶ __-__ below.) The preliminary injunction gives all corn ethanol producers the ability to try to compete again in California as they could before the LCFS regulation took effect.[2]

4. Defendants also claim that the preliminary injunction is jeopardizing reductions in greenhouse gas ("GHG") emissions that were being provided by the LCFS regulation, or that would be provided by the regulation during the pendency of the litigation. (*See, e.g.*, Stay Mot. at 28.) That claim ignores the fact that in 2011, and currently and for the foreseeable future, corn ethanol that cannot be sold in California as a result of the LCFS is still being produced and is being sold in other markets. (*See* ¶¶ __-__ below.) The preliminary injunction is not jeopardizing reductions in GHG emissions from the corn ethanol production sector, because there is no evidence that such reductions occurred as a result of the LCFS regulation. Indeed, the LCFS regulation did not affect, and in the near term will

[2] The exclusion of some producers from the California market and those producers' loss of the "California premium" does not mean that the LCFS regulation has lowered ethanol prices in California. *See* ¶ __ below.

not affect, methods of production or output of that sector, which are determined by macroeconomic factors unaffected by the regulation.

5. This declaration is based on my personal knowledge of the ethanol industry gained in the course of my employment at POET Ethanol Products. I have worked in the transportation fuels industry for more than 17 years, and in the corn ethanol marketing business for more than a decade.[3] My duties at POET Ethanol Products require me to have direct, first-hand knowledge of sales of ethanol by all the production facilities for which we market ethanol. My duties also require me to have a full and current understanding of the methods of ethanol production and delivery throughout the U.S. corn ethanol industry, as well as corn ethanol marketing practices and factors affecting competitive conditions within the

[3] POET Ethanol Products currently markets ethanol from 35 ethanol producers, located in Colorado, South Dakota, Nebraska, Kansas, Missouri, Iowa, Minnesota, Indiana, Ohio, and Michigan.

Some of the ethanol plants for which POET Ethanol Products markets ethanol have management contracts with POET LLC, an ethanol plant construction and management firm based in Sioux Falls, South Dakota. The U.S. Environmental Protection Agency has sometimes referred to "POET Biorefining" as a single ethanol production or marketing entity. (*See, e.g.*, Renewable Fuels Standard Program (RFS2) Regulatory Impact Analysis (Feb. 2010) 97, *available at* http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P1006DXP.txt. In point of fact, nearly every ethanol plant having management contracts with POET LLC is owned by a separate group of investors, which typically include a large number of investors from the farming communities near the ethanol plant, who often sell their grain to the local plant managed by POET LLC to make ethanol.

corn ethanol industry, including the impact of regulations like the LCFS regulation on corn ethanol markets.

6. The balance of my declaration is divided into two parts. Part I provides necessary background on the U.S. corn ethanol industry and the California corn ethanol market. Part II explains how the LCFS regulation affected the U.S. corn ethanol industry in 2011, and would continue to affect that industry in the absence of a preliminary injunction.

I. The Corn Ethanol Industry and the California Energy Market

7. Ethanol is used as an additive in gasoline. It has high octane ratings, and can also be used as an oxygenate to help reduce automotive air pollution. Corn ethanol produced at plants located in the Midwest historically provided about 95 percent of California's requirements for oxygenates for blending into gasoline.

8. All ethanol sold in the United States for use in motor fuel has the same physical and chemical composition, regardless of the method of production or the material from which the ethanol is produced (called the "feedstock").[4] Prior to implementation of the LCFS regulation, ethanol for use in gasoline could be sold as a fungible commodity. The market for corn ethanol for use in gasoline was highly competitive. A successful business plan for a corn ethanol plant required

[4] In the case of ethanol made from corn starch, the type of corn used is "No. 2" corn, the hard corn grown as animal feed, and not so-called "sweet corn" sold in grocery stores for human consumption.

proximity to the corn feedstock, access to competitively priced energy needed in the production process, efficient production technology and methods, and good transport logistics to get the ethanol from the plant to the customers' locations.

9. Transport logistics are particularly important for corn ethanol plants that intend to serve distant energy markets, sometimes located more than a thousand miles from the plant. Plants that produce ethanol for shipment over long distances use railways as a mode of transport, preferably in dedicated "unit trains" of tanker cars that can be loaded at sidings within or adjacent to the ethanol plant's fence line.[5]

10. California is the single largest state market for corn ethanol in the United States, historically consuming about ten percent of total U.S. corn ethanol production. Companies that market gasoline in California blend ethanol into base gasoline, called "California Reformulated Gasoline Blendstock for Oxygenate Blending," or "CARBOB." Publicly available price data show that historically, the California gasoline blenders have paid higher prices on average than could be obtained for ethanol sold in other parts of the United States. While many factors can affect the price paid for ethanol, one factor that likely accounts for the higher prices available in California is that the refineries that produce CARBOB tend to

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[5] A photograph showing the integration of an ethanol plant with its rail connection is attached as Exhibit 1 to the Declaration of Russ Newman, being filed today by Plaintiffs. (*See* [ECF #], Exh. 1.)

have higher average total production costs than refineries outside California. Even after accounting for the costs of shipping ethanol over the Rocky Mountains, Midwest ethanol producers who could obtain a customer base in California obtained over time a higher "net-back" per gallon (*i.e.*, price per gallon to the customer, net of freight costs) than they could obtain in other markets. For example, in the three years prior to implementation of the LCFS regulation at the end of 2010, for example, the average California "net-back" price for a gallon of ethanol was 3.65 cents per gallon ("cpg") higher than the Chicago market, and 4.17 cpg over prices at New York Harbor.[6]

11. To compete in the California ethanol market, investors in Midwest corn ethanol plants have for many years sited their plants in locations with the best possible rail access to California. Those producers are located west of the Mississippi River, often in North and South Dakota, Minnesota, Iowa, Kansas and Nebraska. Their plants are designed at the outset to be "single line" shippers to California, meaning that they can ship their product on either the BNSF or Union Pacific systems, without changing freight lines and having to pay more than one freight bill.

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[6] Based on Platts Fuel Price Service daily reports, Jan. 1, 2008 to Dec. 31, 2010, for Chicago spot prices, New York Harbor 5- to 15-day barge prices, and Southern California rail prices, less average estimates of freight from the Midwest.

II. Impacts of the LCFS Regulation

12. The basic features of the LCFS regulation, as it existed in the summer of 2010 prior to implementation, were described in the District Court's decision denying Defendants' motion to dismiss this case. (*See Rocky Mountain Farmers Union, et al. v. Goldstene*, 719 F.Supp. 2d 1170, 1177-79 (E.D. Cal. 2010).) As first adopted, and in its current form, the LCFS regulation assigns to each gallon of ethanol sold in California a "carbon intensity" (or "CI") score based on the "pathway" assigned to the plant where it is produced. The "pathway" for ethanol is in turn defined by the location where the ethanol is produced, the feedstock used (in the case of corn ethanol, No. 2 Corn), the production method, the consumption of ethanol in a vehicle's engine, and other factors. Carbon intensity is quantified in units of grams of carbon-dioxide-equivalent emissions per megajoule ("g/mj") of energy that the LCFS regulation attributes to each pathway. (*See* 719 F.Supp. 2d at 1178-79, 1197.)

13. The stated goal of the LCFS regulation is to produce reductions in the average carbon intensity of transportation fuels sold at the retail level in California, on a year-by-year basis, starting in 2011, until 2020 when that average carbon intensity is required to be 10 percent lower than before the regulation took effect. For example, the LCFS regulation's carbon intensity reduction schedule for gasoline calls for an average carbon intensity in 2011 of 95.61 g/mj (a reduction of

0.25 percent from a 2006 baseline); by 2020, the average carbon intensity level must be 86.27 g/mj. (10 percent below the 2006 baseline). A gasoline blender achieving a lower level of average carbon intensity than 95.61 g/mj in 2011 would generate a credit against the compliance schedule set by the regulation. A gasoline blender whose blended product exceeded 95.61 g/mj in 2011 would generate a deficit. LCFS credits have an indefinite lifetime. Deficits, however, must be made up by the end of the year following the year in which they were created.

14. From a marketing perspective, the simplest example of how the LCFS regulation works is to start with the fact that the LCFS regulation assigns a CI value of 95.85 g/mj for a baseline gasoline and a CI value of 95.86 to CARBOB. In 2011, the LCFS regulation set a target for the average CI of finished gasoline products at 95.61 g/mj -- a value that is 0.25% lower than the baseline gasoline CI value. An oil company blending CARBOB with ethanol having a CI value greater than 95.86 g/mj would increase, not decrease, the carbon intensity of the final gasoline product it is selling -- which is not what the regulation is trying to accomplish. As such, it would generate a deficit, rather than a credit. For ethanol assigned a CI value lower than 95.86 g/mj, the ethanol product will enable, to some extent, a reduction in the carbon intensity of the final, blended gasoline product. The lower the CI value assigned to a given ethanol pathway, the more valuable the

ethanol is to a gasoline blender trying to reduce the carbon intensity of its final product.[7]

15. As first approved by CARB in 2009, the LCFS regulation assigned a CI value of 98.40 g/mj to the Midwest corn ethanol pathway that represented the majority of Midwest plants, including most members of Growth Energy, one of the Plaintiffs in this action. An oil company blending ethanol from that most typical Midwest pathway would therefore have increased, not reduced, the carbon intensity of its finished gasoline product. At POET Ethanol Products, we saw a shift in the buying preferences of our California customers after the LCFS regulation was adopted. A number of our customers would pay a higher price for ethanol that had lower CI values, and to the extent they would buy ethanol with CI values above the CI level assigned to CARBOB, they would only purchase the ethanol at lower prices. That fact is borne out in one of the Declarations signed by Mr. Michael Waugh and filed in support of Defendants' stay motion, which states that "[w]ith the exception of a few isolated days, spot prices for ethanol with a

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[7] Federal regulations limit the maximum amount of ethanol that can be blended into gasoline, and commercial gasoline blenders do not always decide to blend the highest levels of ethanol allowed by law. At a blend level of 10 percent, as explained in an accompanying declaration, the blended gasoline could not begin to generate any credit for a gasoline blender against the LCFS regulation in 2011 unless it was assigned a CI value below 95.61 g/mj. *See* Declaration of James M. Lyons ¶ __.

carbon intensity value of 90.1 [g/mj.] were at least $0.01/gal higher than with a carbon intensity of 98.4 [g/mj.], during all of 2011."[8]

16. As Mr. Waugh also notes, a number of Midwest corn ethanol producers were able to obtain adjustments in the CI levels assigned to their ethanol, after the LCFS regulation was first approved. (*See* Waugh Decl. ¶¶ 52-59.) Thus, some plants whose ethanol would have been assigned the 98.4 g/mj. carbon intensity level under the original, 2009 version of the LCFS regulation have been able to obtain lower pathways. As explained in an accompanying Declaration, those plants obtained their specific lower carbon intensity pathways by documenting the production technologies, processes, methods, and energy inputs that were already in place and which they would have used in the absence of the LCFS regulation, which the CARB staff then decided would warrant a lower-CI pathway.[9]

17. Neither Mr. Waugh nor any of Defendants' other declarants addresses the fact that, while some Midwest producers were able to provide documentation to

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[8] Declaration of Michael Waugh in Support of Defendants and Defendant-Intervenors' Motion to Stay Preliminary Injunction and Judgments Pending Appeal (Dkt Entry 21-7) ("Waugh Decl.") ¶ 46. Mr. Waugh calls the higher price for lower-CI ethanol a "price premium." *Id*. at 12:19. That higher price for some lower-CI ethanol is not the same as the "California premium" that obtained before the adoption of the LCFS regulation and that is described in Part I of my Declaration.

[9] *See* Declaration of Erin Heupel ¶¶ 5-6.

CARB showing that their ethanol should not be penalized in 2011 with a CI value higher than gasoline, other Midwest plants were unable to do so. Some of the plants that could not document the production technologies, processes, methods, and energy inputs that the CARB staff would reward with lower CI values had previously sold a substantial volume of ethanol in California. The LCFS regulation forced some of those plants entirely out of the California market in 2011. Several of those plants have come forward in this proceeding, and have provided Plaintiffs with declarations that explain the impact of the LCFS regulation on their business.[10]

18. The effect of the LCFS regulation has been to "de-commoditize" the corn ethanol market, for purposes of California -- *i.e.*, ethanol is no longer a fully fungible commodity in California, in which producers can prevail by offering the best commercial terms. Plants that were optimized for shipment of ethanol to California when they were built, but that can no longer sell their ethanol in California, now must find buyers outside California. On an industry-wide basis, the LCFS regulation has led to "fuel shuffling" that has likely increased the number of miles that Midwest corn ethanol had to travel in 2011 in order to get from the production facilities to customer destinations.

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[10] *See* Declaration of Duane Kristensen (impact of LCFS regulation on Nebraska corn ethanol producer); Declaration of Russ Newman (impact on North Dakota producer); Declaration of Delton Strasser (on South Dakota producer).

19. Some of the Midwest plants that were excluded from the California market in 2011, especially those built to serve California, have been required to ship their product using multiple-stage freight movements, which increased the costs of delivery to the customers. Those plants have lost the ability to compete for the lucrative California market, and have also been required to incur higher costs to sell at lower prices elsewhere, as their logistics for delivery have become more complex. Defendants ignore those impacts on the producers who have been excluded from California. The preliminary injunction issued by the District Court is essential to efforts by those producers to try to re-enter the California market and to compete for sales.

20. For all the disruptions in the California ethanol market created by the LCFS regulation, there has been no reduction in the overall amount of corn ethanol produced in the United States, or used as a motor fuel in this country or overseas. (As Mr. Waugh notes, U.S. ethanol producers have recently been shipping some ethanol overseas.) The overall production levels for corn ethanol last year, and for the foreseeable future, depend on macroeconomic factors (including demand for gasoline) that are independent of the LCFS regulation.

21. In conclusion, although Defendants claim that the "LCFS was expected to result in emissions reductions [in California] of almost one million metric tons (MTs) in 2012 and almost two million in 2013," and that "[t]hose

targets would be achieved with a stay" of the preliminary injunction" (Stay Mot. at 28), those claims have no basis in fact. The same amount of corn ethanol would have been produced in the United States in 2011 in the absence of the LCFS regulation, and renewed enforcement of the LCFS regulation cannot be predicted to have any impact on national production of corn ethanol during the pendency of this litigation. The only effect of the LCFS is to cause ethanol "shuffling" by which some lower CI corn ethanol that would have been sold elsewhere is instead shipped to California while the higher CI corn ethanol that would have otherwise been sold in California is sold elsewhere.

22. Finally, I note that Defendants' claim that any GHG emissions that occurred in 2011 "will be lost" in the absence of a stay. (*Id*.) Buyers in the California ethanol market typically purchase their requirements in multi-month, forward contracts. Even if one were to credit Defendants' claim (which is incorrect, for the reasons explained above) that the LCFS regulation affected production of ethanol in 2011 in a way that reduced GHG emissions, the preliminary injunction issued by the District Court on December 29, 2011, has had no impact on ethanol delivered in California under those contracts..

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct. Executed on March 1, 2012 at Wichita, Kansas.

____

Robert Whiteman

Appendix F

growth energy
America's Ethanol Producers

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October 31, 2014

By Electronic and U.S. Mail

Dr. Irena Asmundson
Chief Economist
California Department of Finance
915 L Street
Sacramento, CA 95814

Stephen Adams, Esquire
William Brieger, Esquire
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Standardized Regulatory Impact Assessments for the Low-Carbon Fuel Standard and Alternative Diesel Fuel Rulemakings

Dear Dr. Asmundson and Messrs. Adams and Brieger:

Thank you for providing public access to the combined standardized regulatory impact assessments (the "CSRIA") for the low-carbon fuel standard ("LCFS") and alternative diesel fuel ("ADF") rulemakings. I write in order to present some specific questions based on Growth Energy's review of the CSRIA. The first set of questions are intended for the ARB Chief Counsel's Office, and the second set are intended for both the Department of Finance and the ARB Chief Counsel's Office. Let me state at the outset that Growth Energy appreciates the opportunity to participate in the SB 617 process for these two important rulemakings, and the consideration that the ARB staff has given to its submittals. Growth Energy regrets that more information about the goals and the estimated benefits or costs of the LCFS and ADF proposals was not available to stakeholders prior to the time when alternative proposals had to be submitted.

1. Evaluation of ADF Alternatives

Based on some recently-received information (*see* Attachment A), it appears that the ADF portion of the CSRIA does not present ARB's currently proposed regulatory approach to mitigate emissions increases that would be caused by the use of biodiesel fuels in order to comply with the LCFS regulation. As Mr. Adams confirms in Attachment A, ARB does not plan to require mitigation for any biodiesel blends below five percent ("B5"). This is contrary to what the CSRIA describes as ARB's proposal for the ADF regulation, which would require mitigation for some biodiesel blends at concentrations greater than one percent. (*See* CSRIA at 4.) Growth Energy appreciates Mr. Adams' prompt clarification of what the ARB staff is currently planning to consider as part of the ADF regulation.

In light of this clarification, Growth Energy would like to inquire whether the ARB staff plans to revise the portion of the CSRIA that discusses Growth Energy's proposed alternative to the ARB proposal. The CSRIA states at one point that the Growth Energy alternative "may achieve more emissions benefits" than ARB's proposal under some circumstances (CSRIA at 22), but then later states that the Growth Energy alternative "does not result in any more emissions reductions than the ADF proposal." (*Id.*) Those two statements appear to contradict one another.

The threshold question is whether the ARB staff intended to state that the Growth Energy proposal would, or would not, result in greater emissions reductions than the ARB proposal (as now clarified). The first quoted portion of the CSRIA refers to possible emissions reduction benefits under the Growth Energy proposal "if biodiesel were to be widely used as an additive under the ADF proposal." (CSRIA at 22.) Based on the ARB staff's projections (and treating biodiesel as "an additive"), biodiesel will certainly be "widely" used in many parts of the State and for many years. If the ARB staff disagrees, or if it meant something different when referring to the use of biodiesel as an "additive," please explain the reason for disagreeing, or clarify what "additive" means in this context.

The next question assumes that ARB did, in fact, intend to acknowledge that the Growth Energy proposal would be more protective -- provide more emissions reductions -- than the ARB proposal. On that premise, please advise whether ARB intends to revisit its position that the Growth Energy proposal would only provide "marginally more emissions benefits" than the ARB proposal, now that it is clear that ARB proposes not to require mitigation of any biodiesel blends below B5. In order for Growth Energy and others, including the Department of Finance, to understand the amount of incremental benefit that ARB would assign to the Growth Energy proposal, please also indicate how the staff has quantified that increment, and provide the inputs and assumptions on which that quantification is based.

2. Evaluation of LCFS Alternatives

The CSRIA appears to treat Growth Energy's proposed alternative to the LCFS proposal as not requiring complete assessment under the governing statute and regulations. Thus, referring to Growth Energy's proposed alternative ("this alternative") and to the CSRIA itself ("this document"), Appendix A of the CSRIA states as follows:

> ARB is required to analyze only those alternatives that are reasonable and that meet the goals of the program as required by statute. An initial assessment of the program indicates the goals of the LCFS proposal can be achieved by keeping the program '...separate of the AB 32 Cap-and-Trade system initially (at least first 10 years) in order to stimulate innovation and investment in low-GWI [global warming intensity] fuel (or transportation) technologies.' Due to the strong justifications that the Cap-and-Trade program alone generates neither the CI reductions nor fuel in the transportation sector, ***this alternative will not be assessed in this document.***

CSRIA at 27 (footnote omitted; emphasis added). The CSRIA concedes that Growth Energy's proposed alternative would "likely" achieve the same "estimated GHG emissions reductions" as the current regulation in the period up to 2020. (*Id.* at 26-27.)

The deficiency in the Growth Energy proposal, according to the CSRIA, is not that it creates a GHG emissions reduction shortfall at any point prior to the end of the current regulatory horizon; instead, the problem is that the Growth Energy proposal does not rely on the same strategy of fuels diversification and achievement of GHG emissions reductions as proposed by ARB. As Appendix A of the CSRIA explains:

> Transportation in California was powered almost completely by petroleum fuels in 2010. ... Transitioning California to alternative, lower-carbon fuels requires a very focused and sustained regulatory program tailored to that goal. ... In the absence of such a program, post-2020 emissions reductions would have to come from a transportation sector that would, in all likelihood, have emerged from the 2010-2020 decade relatively unchanged. ***In the absence of an LCFS designed to begin the process of transitioning the California transportation sector to lower-carbon fuels starting in 2010, post-2020 reductions would be difficult and costly to achieve.*** This is why the primary goals of the LCFS are to reduce the carbon intensity of California fuels, and to diversify the fuel pool. A transportation sector that achieves these goals by 2020 will be much better positioned to achieve significant GHG emissions reductions post-2020.

CSRIA at 27 (emphasis added). In essence, the CSRIA is claiming that fuels diversification and carbon intensity requirements are necessary in order to make post-2020 greenhouse gas reductions less costly and less difficult to achieve. Growth Energy would submit, with the greatest respect, that the stated rationale for not providing a complete assessment of its alternative is itself deficient.[1] These are the salient points:

- The LCFS regulation does not require, and based on ARB publications is not expected to result in, the production or use of any type of alternative fuel that other regulations do not already either require or cause to be used in California. The federal renewable fuels program is intended to provide for the production and sale of cellulosic and "advanced" biofuels in the same time frame as the LCFS regulation. While the federal program does not require the use of electricity or hydrogen as a transportation fuel, the California motor vehicle emissions control and zero-emission vehicle programs do.[2]
- The long-run, post-2020 plans for greenhouse gas reductions developed by ARB calls for the phase-out of reliance on liquid biofuels.[3] Eventually, the State plans to eliminate gasoline, in

[1] Elsewhere, the CSRIA states that a goal of the LCFS regulation is to "create a durable regulatory framework that can be adopted by other jurisdictions." (CSRIA at 2.) ARB's authorizing legislation directs and permits the Board to adopt regulations to reduce greenhouse gas emissions. The statute does not permit the Board to impose costs on California consumers and businesses in order to export regulations to "other jurisdictions." Notably, the CSRIA does not try to claim that adoption of the LCFS program outside California will reduce costs. To the contrary, adoption of the LCFS program in other jurisdctions is likely to create supply shortages for the lowest-carbon-intensity alternative fuels, and could increase compliance costs for California consumers and businesses.

[2] *See* Attachment B (Growth Energy's proposed alternative to the LCFS regulation) at 8-11 (describing programs that will achieve the fuels diversification sought by ARB, in the absence of the LCFS regulation).

[3] *See* http://www.arb.ca.gov/planning/vision/vision.htm.

particular, from use in California cars and trucks and fully to replace gasoline with electricity. Putting to the side whether ARB's post-2020 strategy is meritorious, the CSRIA does not explain why ARB would seek to impose costs on California consumers and businesses to foster the use of fuels that (according to ARB) are destined for a diminishing, and no long-term, role in its greenhouse gas reduction strategy.

- ARB's authorizing legislation does not itself require the use of regulations intended to reduce the carbon intensity of transportation fuels to achieve greenhouse gas reduction; it requires that enacted regulations achieve "the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions."[4] If the CSRIA's premise is that regulation of the carbon-intensity of transportation fuels is necessary now in order to reduce the costs or difficulties of achieving greenhouse gas reductions after 2020, as the State transitions away from biofuels, then the CSRIA should have included (i) an identification of the desired reductions in greenhouse gas emissions in the transitional period, and (ii) a sufficient explanation of why the costs of achieving those reductions would be reduced if Californians paid now for compliance with an otherwise unnecessary regulatory program. On a net-present value basis, there is reason to doubt that reliance on the LCFS regulation up to 2020 is the most cost-effective way of reducing greenhouse gas emissions after 2020 -- particularly when ARB would still have authority under its authorizing legislation to adopt and enforce regulations requiring reductions in the carbon-intensity of transportation fuels after 2020.

Appendix A of the CSRIA therefore uses unsupported speculation about future regulatory costs and strategies, and an unspecified target for a future regulation (a regulation to reduce greenhouse gas emissions resulting from the use of liquid biofuels after 2020), as reasons to not provide a complete assessment of the Growth Energy alternative. The question presented is whether the CSRIA is substantially compliant with the Government Code, as amended by SB 617, and with the Department of Finance's implementing regulations.

Section 11346.36 of the Government Code provides that standardized regulatory impact assessments must compare

> [P]roposed regulatory alternatives with an established baseline so agencies can make analytical decisions for the adoption, amendment, or repeal of regulations necessary to determine that the proposed action is the most effective, or equally effective and less burdensome, alternative in carrying out the purpose for which the action is proposed, or the most cost-effective alternative to the economy and to affected private persons that would be equally effective in implementing the statutory policy or other provision of law.

Cal. Gov't Code § 11346.36(b)(2). The Department of Finance's SRIA regulations accordingly require among other things that agencies "should consider" including in their analyses the "assumptions" and "data" used in the evaluation of regulatory alternatives and use "an established baseline" in evaluating "feasible alternatives" to a regulatory proposal. 1 C.C.R. §§ 2003(e), (e)(5). In addition, another portion

[4] Cal. Health & Safety Code § 38562(a).

of those regulations requires agencies to consider "how the effects of the regulation are distributed over time," including costs and benefits. *Id.* at § 2003(e)(4).

The Department's regulations do not specifically provide that agencies may exclude some proposed alternatives from stakeholders from complete analysis. Whether or not the discussion of Growth Energy's proposed alternative to the LCFS proposal in Appendix A is considered as complete as the evaluation of the regulatory alternatives considered in the main text of the CSRIA, ARB's rejection of Growth Energy's alternative does not meet the requirements of the Government Code, as amended by SB 617.

The CSRIA concedes that Growth Energy's alternative is likely to achieve the same level of greenhouse gas emissions reductions as the ARB proposal within the time frame for specific emissions reductions (2010-2020) defined by the ARB proposal. The CSRIA does not identify a single alternative fuel that other regulations will not require to be produced and used in California. (*See* note 2 above.) The questions that ARB was therefore required to address are whether the Growth Energy alternative is (i) "equally effective and less burdensome in carrying out the purpose for which the action is proposed," and (ii) would be "the more cost-effective alternative." Cal. Gov't Code § 11346.36(b)(2). ARB's negative answer to those two questions posed in the statute depends on its unsupported notions about how the use of carbon intensity regulations now will ease and reduce the costs of greenhouse gas reductions after 2020. ARB has provided the Department with no basis on which to evaluate, much less to credit, its belief that imposition of the regulatory costs of the LCFS program now will reduce the costs of post-2020 greenhouse gas reductions. Without more, there is no basis to conclude that the ARB proposal is more cost-effective than the Growth Energy alternative.

The enactment of SB 617 requires ARB to employ a level of analytical rigor and transparency in the current rulemaking that may not have been required in 2009, when the Board embarked on the regulation of carbon intensity. Likewise, SB 617 requires the Department of Finance to ensure that agencies meet the requirements of SB 617, including what is now section 11346.36 of the Government Code. ARB may contend that the requirements of sections 2002 and 2003 in the Department's regulations are merely precatory, because, for example, section 2003 only lists what an agency "should" consider in the analytical process. That is a question for the Department to consider, as indicated below; regardless, under the text of the Government Code, either the CSRIA does not meet the requirements of the Department's regulations, or those regulations are themselves deficient.

Growth Energy therefore suggests that the Department of Finance and the ARB Chief Counsel's Office consider and respond independently to the following questions:

- Whether the requirements for regulatory analysis contained in sections 2002 and 2003 of the Department's regulations are mandatory for all major rulemakings;
- Whether the Department's regulations allow an agency to engage in two different levels of review and consideration of regulatory alternatives, in the manner apparently pursued by ARB in the LCFS and ADF rulemakings;
- Whether the Department has the authority, or the duty, to refuse to comment upon, or otherwise reject, a standardized regulatory impact analysis that does not contain the information and analysis required by sections 2002 and 2003 of its regulations;

- Whether the CSRIA's reliance on speculative and unquantified future (post-2020) estimated cost savings meets the requirements of SB 617 and the Department's regulations, particularly the portions of those regulations that require adequate definition of a baseline, comparative cost-effectiveness assessments, a discussion of "uncertainties associated with … estimates," and attention to how the effects of a regulation (both costs and benefits) may differ in their timing. *See* 1 C.C.R. § 2003(e), (e)(3), (e)(3)(D), (e)(4), (e)(5); and
- If the CSRIA meets the requirements of the Department's current regulations, whether those regulations should be amended in order to more effectively permit the evaluation of alternatives required inter alia by section 11346.36(b)(2) of the Government Code.

Thank you again for allowing Growth Energy to participate in the SB 617 process for these two regulations. I would appreciate it if you would advise me whether and how the Department and the ARB Chief Counsel's Office plan to respond to the specific questions presented in this letter. In addition, please let me know if you would like to discuss the issues raised here, including the questions that Growth Energy hopes you will consider and address.

Sincerely,

David Bearden

David Bearden
General Counsel and Secretary

cc: Mr. Michael Waugh (by electronic mail)
Mark W. Poole, Esquire (by electronic mail)
Elaine Meckenstock, Esquire (by electronic mail)

Attachment A

Drake, Stuart

From: Adams, Stephen@ARB <Stephen.Adams@arb.ca.gov>
Sent: Wednesday, October 29, 2014 2:34 PM
To: majorregulations@dof.ca.gov
Cc: Drake, Stuart; Brieger, William@ARB; Elaine Meckenstock (Elaine.Meckenstock@doj.ca.gov)
Subject: FW: LCFS and ADF rulemakings -- SRIAs

To whom it may concern:

The emails below relate to the SRIA that ARB staff submitted on October 17 for the low-carbon fuel standard regulation and alternative diesel fuel regulation. This copy is being provided for your information.

Stephen Adams
ARB Senior Staff Counsel

From: Adams, Stephen@ARB
Sent: Wednesday, October 29, 2014 11:28 AM
To: 'Drake, Stuart'
Cc: Brieger, William@ARB; Elaine Meckenstock
Subject: RE: LCFS and ADF rulemakings -- SRIAs

Stuart,

The differences you point to between the biodiesel mitigation described in the SRIA and that presented at the Oct. 20 workshop reflects the progression in staff's analysis of the biodiesel NOx issue and mitigation for NOx emissions from biodiesel. You're correct that the SRIA describes a plan to require mitigation for blends from B1 and higher, while the proposal discussed at the workshop would require mitigation beginning at blends of B5 and higher. The reasons behind these changes were described at the workshop, and also on page 2 of the discussion paper that you cite.

Time constraints prevented staff from revising the SRIA to reflect staff's more recent approach. Although the SRIA was submitted to the Department of Finance on the same day that workshop materials were made available, the modeling and analysis work to prepare the SRIA was a weeks-long process. The SRIA as submitted discloses potential economic impacts from the ADF, and the economic impacts from staff's revised approach will likely be lower than stated in the SRIA. I'd also note that the issues of biodiesel NOx emissions and mitigation are still the subject of internal discussion and analysis, and consequently these provisions are subject to further changes prior to filing of the proposed regulation with the Office of Administrative Law.

The economic impact analysis for the ADF will be updated as we move forward. Regulatory concepts and proposals are often revised during their development and public review, especially at this preliminary stage. Given that, changes such as the one involving staff's evaluation of biodiesel emissions are to be expected.

Sincerely,

Steve

From: Drake, Stuart [mailto:sdrake@kirkland.com]
Sent: Tuesday, October 28, 2014 6:30 AM
To: Adams, Stephen@ARB

Cc: Brieger, William@ARB; Elaine Meckenstock
Subject: LCFS and ADF rulemakings -- SRIAs

Steve --

The Department of Finance yesterday provided Growth Energy and other members of the public with access to the October 17, 2014 SRIA that covers the ADF rulemaking. Thank you for helping to make that happen. I'd like to request your Office's further assistance with what appears to be a substantial problem in one portion of the SRIA. That is the portion of the SRIA that describes the staff's proposed mitigation strategy to the Department of Finance and others.

Page four of the SRIA describes the mitigation strategy for the staff's ADF proposal in relevant part as follows (emphasis added):

> "The multimedia evaluation process for biodiesels made from various feedstocks identified a NO_X significance threshold, or blend level, that will result in no significant adverse impacts. The ADF proposal seeks to mitigate NO_X impacts from biodiesel by setting a significance threshold and requiring mitigation of all non-animal biodiesel use at blends above one percent, and all animal biodiesel used at blends above five percent. *The ADF proposal identified one percent for non-animal biodiesel, rather than zero percent, because biodiesel may be used as an essential lubricity additive at one percent or less.*"

I am not aware that anyone has called for mitigation when there is zero percent biodiesel in the blend. Growth Energy has proposed mitigation below the five percent level (or "B5") if the blend level was one percent or greater, as the SRIA elsewhere notes. (*See* SRIA at 22.) In any event, a fair reading of the SRIA is that the ARB decided, as of October 17, to require mitigation of all non-animal biodiesel use at blends above one percent.

I believe there may be some material confusion about the ARB staff's position. The confusion arises because the staff appears to be saying different things in its filings with the Department of Finance and in some of its public statements. Appendix A of the ADF regulatory "discussion paper" released by the ARB staff on the same day as the SRIA (October 17) describes the staff's ADF proposal as follows:

> " Recognize biodiesel made from soy feedstocks as low saturation (i.e., B100 with cetane <56) and biodiesel made from animal feedstocks as high saturation (i.e., B100 with cetane ≥56).
>
> " Establish significance thresholds of B5 for low saturation biodiesel, and B10 for high saturation biodiesel to ensure NOx impacts associated with biodiesel use do not increase and steadily decrease. Allow 'Safe Harbor' blending below the significance threshold without the need for additional NOx mitigation."

See http://www.arb.ca.gov/fuels/diesel/altdiesel/20141017_ADF_discussion_paper.pdf. That proposal (mitigation of non-animal based, aka "low saturation" biodiesel, at B5 and higher) was discussed at the ARB staff's workshop on October 20. So, in a nutshell, the SRIA indicates that mitigation will be required for non-animal biodiesel with blend levels above one percent; by contrast, the "discussion paper" and the staff's presentation to the public at its October 20 2014 workshop, indicated that mitigation would only be required for animal-based blends at or above five percent.

If the blend level at which the staff proposal would require mitigation is material enough to have been presented in the SRIA, then this apparent inconsistency in the relevant blend level for mitigation is also material. The SRIA advises the Department of 2inance that the staff's proposal "will result in no significant adverse impacts on public health or the environment." (SRIA at 3.) The Department might reasonably believe that the SRIA's claim in that regard was based on mitigation for animal-based biodiesel blends between one and five percent, based on the portion of the SRIA appearing on page 4 that is quoted above. The likelihood that the Department will be misled -- I assume inadvertently -- about this basic element in the staff's AD2 proposal is sufficient in itself to require correction. In addition, the inconsistency is also relevant to the reasonableness of the staff's claim in the SRIA that the Growth Energy alternative proposal "does not result in any more emissions reductions than the AD2 proposal." (SRIA at 22.) Presumably, in evaluating that claim, the Department would want to know that the staff's proposal does not require mitigation for non-animal based biodiesel at the same level as does the Growth Energy proposal.

If I am missing something that explains why the description of the staff's AD2 proposal in the SRIA does *not* differ materially from the description in the materials that the staff has released to the public on October 17, please let me know. If the staff's proposal really is to require mitigation for non-animal blends higher than one percent (even if less than five percent), please let me know. Otherwise, Growth Energy would like to know how the staff plans to correct the SRIA, so that the Department and others will have an accurate understanding of the staff's proposal.

On the assumption that the Department has to provide its evaluation of the SRIA very soon, Growth Energy requests a response to this inquiry by the close of business on Wednesday, October 29.

Please let me know if you would like to discuss these questions, or if you don't believe that the staff will be able to respond by the close of business on October 29. Thanks, Stuart

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Attachment B

STATE OF CALIFORNIA

AIR RESOURCES BOARD

RESPONSE TO REQUEST FOR PUBLIC INPUT ON ALTERNATIVES TO THE LOW- CARBON FUEL STANDARD REGULATION

GROWTH ENERGY

JUNE 23, 2014

Executive Summary

The staff of the California Air Resources Board ("CARB") has identified the Low-Carbon Fuel Standard ("LCFS") as a "major regulation" that requires enhanced review for compliance with SB 617 (Calderon and Pavley), a 2011 amendment to the California Administrative Procedure Act (the "APA"). The California Department of Finance ("the Department") has published regulations that implement SB 617. Those regulations require rulemaking agencies like CARB to seek early public input on possible alternatives to the rules being developed by the rulemaking agencies.

Growth Energy, an association of the Nation's leading ethanol producers and other companies that serve America's need for renewable fuels, is submitting to the CARB staff a proposed alternative to the LCFS regulation that would allow the State to eliminate the LCFS program without loss of environmental benefits. Growth Energy's proposal recognizes important changes in the regulatory baseline for the control of greenhouse gas ("GHG") emissions that have occurred since 2009. In particular, the federal renewable fuels standard ("RFS") program, combined with the California cap-and-trade program and a number of California-specific vehicle- and engine-based regulations, now assure that California will receive most if not all of the direct GHG emissions reductions that can be attributed to the LCFS regulation. To the extent that CARB believes that there is still an emissions shortfall from elimination of the LCFS or that it has authority to address lifecycle GHG emissions occurring outside of California under state and federal law (which are issues not addressed in this submittal), Growth Energy proposes that CARB address those remaining issues by modifying the California GHG cap-and-trade regulations, which are now in effect in California and which apply to transportation fuels providers beginning in 2015.

Growth Energy's description of its proposed alternative to the LCFS regulation is as detailed as possible, given currently available information. In this submittal, Growth Energy urges the CARB staff to provide the additional information needed to provide further analysis of alternatives to the LCFS regulation.

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Growth Energy's Response to Request for Public Input
On Alternatives to the Low-Carbon Fuel Standard Regulation

Growth Energy respectfully submits this response to the request by the staff of the California Air Resources Board ("CARB") for public input on alternatives to the low-carbon fuel standard ("LCFS") regulation. The CARB staff presented its request for public comment in a notice dated May 23, 2014, and has established today as the deadline for that input.

The CARB staff is seeking public input in connection with its proposal that CARB revise and readopt the LCFS regulation at a public hearing later this year. The purpose of the LCFS regulation, which the Board first adopted in 2009, is to achieve reductions in greenhouse gas ("GHG") emissions from the California transportation sector pursuant to the Global Warming Solutions Act of 2006, commonly called AB 32. Other regulations adopted since 2008 under AB 32 to achieve the same objectives as the LCFS regulation include the "cap and trade" regulation (17 C.C.R. §§ 95801-96022), the GHG emissions standards contained in the Advanced Clean Cars (or "ACC") program (13 C.C.R. §§ 1960.1-1962.2), and a set of regulations to control GHG emissions from heavy-duty vehicles and engines.[1]

Overview

Growth Energy has organized its analysis of alternatives to the LCFS regulation in this submission into four parts.

Part I of this submission briefly outlines the statutory and regulatory framework for the CARB staff's request for input on alternatives to the LCFS regulation. As explained in Part I, regulations adopted by the California Department of Finance pursuant to a recent amendment to the APA require CARB to seek and permit effective early public input on rulemaking concerning

[1] These include California's Heavy-Duty GHG regulations now completing the rulemaking process, a second phase of regulations that are under development, and the so-called "Tractor-Trailer" GHG regulation adopted in 2008. *See* http://www.arb.ca.gov/regact/2013/hdghg2013; http://www.arb.ca.gov/cc/hdghg/hdghg.htm.

"major" regulations, including the LCFS. That amendment was contained in SB 617 (Calderon and Pavley). The LCFS rulemaking, and this stage of the LCFS rulemaking, are particularly important, because this rulemaking is one of the first CARB rulemakings governed by SB 617. *See* pp. 4-7 below.

Part II of Growth Energy's submittal addresses some of the important factors that affect a regulatory alternatives analysis undertaken under SB 617. Since 2009, there have been significant changes in the "baseline" conditions for GHG regulation relevant to the LCFS program. As explained in Part II, most of the GHG emissions reductions sought by CARB when it adopted the LCFS regulation in 2009 will be provided by a combination of the federal renewable fuels standard ("RFS") program, along with California's cap-and-trade regulation, ACC program, and regulations limiting GHG emissions from heavy-duty vehicles and engines. Given that most, if not all, of the GHG emissions reductions sought by CARB in 2009 through the LCFS regulation are now assured by those other programs, the LCFS regulation has been rendered largely superfluous from an environmental perspective, even though it imposes huge financial burdens on the regulated community and requires a large commitment of resources by CARB. As a threshold matter, CARB should therefore carefully and fully consider whether, based on regulatory and program developments related to GHG emission control since 2009, there is any continuing need for the LCFS regulation. *See* pp. 8-14 below.

Part III of this submittal explains that, to the extent that the CARB staff finds any continuing need for the LCFS regulation to control GHG emissions, that need could be met instead through a simple modification of the cap-and-trade regulation. Taking that step -- modifying the cap-and-trade regulation -- would fully eliminate any conceivable remaining need for the LCFS regulation, while doing nothing to alter CARB's overall regulatory strategy to address GHG emissions from the California transportation sector. The GHG emissions reductions benefits of the LCFS program would be fully realized from the suite of other GHG regulations adopted federally and in California since 2009, and by the modification of the cap-and-trade program. The direct regulatory costs of the LCFS program are borne primarily by the California motor vehicle fuels marketing industry, which can to some extent pass those costs to its retail customers. Insofar as the LCFS program imposes costs on California businesses and consumers, the alternative presented here (relying on the cap-and-trade program) would not materially alter the allocation of costs and would at the same time reduce regulatory costs by eliminating an entire regulatory program (the LCFS regulation). Judging from the strong concern about the LCFS regulation expressed by oil industry stakeholders, the regulatory relief and reform proposed here warrants full consideration and further development. *See* pp. 14-20 below.

Part IV of Growth Energy's submittal recommends specific next steps that CARB should consider, including full involvement by the Chief Counsel's Office to ensure compliance with the APA. As will be apparent throughout this submittal, Growth Energy's analysis of regulatory alternatives can be no more detailed than the publicly available information about (i) the new version of the LCFS regulation that the CARB staff is considering for proposal to the Board, and (ii) the information that the CARB staff has provided about the benefits that it is attributing to the LCFS program. Contrary to the position taken in communications to Growth Energy by CARB's Transportation Fuels Section on this subject, very little information on the new version of the LCFS regulation or its estimated benefits -- which are critical to an effective SB 617 process -- has been provided to the public to date. In order to achieve substantial compliance with the APA, the CARB staff needs to provide the public with a full picture of its proposed new

LCFS regulation, and in particular describe any new features of the regulation intended to reduce compliance costs. The CARB staff also needs to completely identify for the public all benefits that it is attributing to the LCFS regulation that would bear on an SB 617 alternatives analysis. Then, after the public has had sufficient time to analyze the relevant information from CARB, the public should be permitted to provide updated regulatory alternative analyses, which the CARB staff should fully consider and address in the Standardized Regulatory Impact Assessment required by 1 C.C.R. § 2002. That approach would ensure compliance with the APA, without conflicting or otherwise undermining any other mandates or obligations applicable to the LCFS regulation. *See* pp. 20-24 below.

I. The Statutory Framework for the Regulatory Alternatives Analysis under SB 617

The CARB staff is seeking submittals from the public on regulatory alternatives to the LCFS regulation because it has a legal obligation to do so. For many years, section 11346.3 of the APA has provided in part as follows:

> (a) State agencies proposing to adopt, amend, or repeal any administrative regulation shall assess the potential for adverse economic impact on California business enterprises and individuals, avoiding the imposition of unnecessary or unreasonable regulations or reporting, recordkeeping, or compliance requirements. ...
>
> (2) The state agency, prior to submitting a proposal to adopt, amend, or repeal a regulation to the office, shall consider the proposal's impact on business, with consideration of industries affected including the ability of California businesses to compete with businesses in other states. For purposes of evaluating the impact on the ability of California businesses to compete with businesses in other states, an agency shall consider, but not be limited to, information supplied by interested parties.

Cal. Gov't Code § 11346.3(a)(2). Based on evidence that rulemaking agencies did not adequately consider the burdens that regulations impose on the public, in SB 617 the Legislature added a requirement that rulemaking agencies prepare a detailed assessment of the costs and benefits of any proposed major regulation, for review by the California Department of Finance ("the Department") ***before*** initiating the traditional informal rulemaking process. *See id.* § 11346.3(c). Those detailed assessments are called Standardized Regulatory Impact Assessments (or "SRIAs."). *See id.* § 11346.36. The Legislature also made it clear in SB 617 that the obligation to consider and use early public input on regulatory impacts could not be met by merely going through the formalities of seeking public input.[2]

The Department completed work on regulations to implement SB 617 in the fall of 2013. The Department's regulations require, among other steps, the following:

> The [rulemaking] agency shall also seek public input regarding alternatives from those who would be subject to or affected by the regulations ... prior to filing a notice of proposed action with OAL unless the agency is required to implement federal law and regulations which the agency has little or no discretion to vary. An agency shall document and include in the SRIA the methods by which it sought public input.

1 C.C.R. § 2001(d). As the rulemaking file for the Department's regulations implementing SB 617 shows, many state regulatory agencies, CARB not excepted, recognized that SB 617 (as implemented by the Department) would mean the end of "business as usual" in the California rulemaking process.[3]

In responding to objections from rulemaking agencies concerning the obligations created by its SB 617 regulations, the Department explained that "[i]nvolving the Department and affected parties early in the [rulemaking] process could result in the discovery of additional and

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2 Thus, SB 617 deleted text from section 11346.3(a)(2) of the APA that, up to 2011, had provided that the APA's public-input requirements were not "inten[ded]" to "impose additional criteria on agencies" engaged in rulemaking. *See* Stats. 2011, c.496 (SB 617), subd. (a); Cal. Office of Admin. Law, *California Rulemaking Law under the Administrative Procedure Act* (2012) 57 (legislative history of section 11346.3).

3 Several rulemaking agencies filed sharp objections to the Department's proposed regulations to implement SB 617 on the ground that the regulations would require major changes in the timing used by the agencies to develop regulations and to obtain public input. *See, e.g.*, Dep't of Finance, *Regulations to Implement SB 617 Re Major Regulations, Responses to 45-day Comment Period (Chart A)* (hereinafter "Chart A"), available at http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/documents/Response%20to%20Comments%20Chart A.pdf. The Department dealt fully with all those objections and made no material changes in its proposed regulations to implement SB 617.

perhaps more cost-effective alternatives to [a] proposed major regulation, consistent with the intent of SB 617."[4] Similarly, when rulemaking agencies (including CARB) objected to the burdens of preparing the early regulatory analyses of costs and benefits needed for an effective SB 617 process, the Department correctly concluded that the amended APA "clearly contemplates that an agency will have considered [regulatory] alternatives prior to filing a notice of a proposed action" with the Office of Administrative Law and publication of the regulatory notice for further public comment.[5] The Department also made it clear that under the SB 617 process, the "no action" alternative to regulation -- which is an outcome seldom if ever seen in a major California rulemaking -- had to receive full and fair consideration at the beginning of the rulemaking process.[6]

In requiring significant change in the California rulemaking process, the statute and the implementing regulations are salutary. The LCFS regulation in 2009 was typical of major rulemakings affecting the motor vehicle fuels industries in California. Beginning in 2008, CARB had convened a series of public consultation meetings prior to its formal proposal for rulemaking in March 2009. Not until publication of the Initial Statement of Reasons for the LCFS regulation, however, was the public given any opportunity to review the economic analysis of costs and benefits for the proposed regulation; the written comments on economic issues were due a scant 45 days later (in April 2009), and at the Board's April 2009 public hearing, most private-sector speakers were limited to five minutes to make a presentation to

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[4] *See* Chart A at 24.

[5] *Id.* at 27.

[6] *Id.* at 47-48.

CARB. The public cannot have a significant role in serious economic analysis of a major regulation within such a constrained process.

Unsurprisingly, major economic assumptions and issues were not fully addressed within the time frame for written comments in March to April 2009, nor at the Board hearing. Among the assumptions and factors that could not as a practical matter be "pressure-tested" in the public comment process was the CARB staff's belief that advanced ethanol production methods would eventually drive down gasoline costs at the retail level and make the LCFS program cost-neutral for California consumers or even generate savings of up to $11 billion.[7] That assumption was unsound in 2009, and has since been disproven by experience.[8] Likewise, in the 2009 rulemaking, the CARB staff gave little attention to the ability of the federal RFS program to accomplish the same goals and purposes of the LCFS regulation, and offered largely opaque comparisons between the GHG reductions that the two programs could achieve. Now in its fifth year of implementation, the LCFS regulation has made little or no impact on the supply of lower-GHG fuels in California.[9] SB 617 and the Department's implementing regulations require the Board to improve the quality and depth of the economic analysis for major regulations like the LCFS program.

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7 Air Resources Board, *Proposed Regulation to Implement the Low Carbon Fuel Standard -- Staff Report: Initial Statement of Reasons* (hereinafter "ISOR") at ES-26.

8 As the ISOR itself noted, "Economic factors, such as tight supplies of lower-carbon-intensity fuels ... could result in overall net costs, not savings, for the LCFS." The fact that the cost savings forecast in 2009 proved ephemeral is implicit in the CARB staff's decision, less than two years after the regulation went into effect, to develop "cost reduction" features for the LCFS regulation, which would assist "regulated parties ... unable to meet their compliance obligations ... due to limited supplies of low carbon fuels or LCFS credits in the market." Air Resources Board, *Low Carbon Fuel Standard 2011 Program Review Report* (Dec. 8, 2011) (hereinafter "2011 Program Review") 16.

9 There have been substantial increases in the efficiency of Midwest corn ethanol production facilities since CARB first embarked on the LCFS rulemaking, and those increases have reduced the lifecycle GHG emissions of those facilities under some analyses; but those reductions in GHG emissions have been caused by market forces (the need to reduce energy consumption in order to remain competitive), not by virtue of the LCFS regulation. *See* note 25 below.

II. Factors Affecting the Regulatory Alternatives Analysis

According to the CARB staff, the goal of the LCFS regulation in 2009 was, and still remains, to "reduce the carbon intensity of transportation fuels used in California by at least 10 percent by 2020 from a 2010 baseline," and also to "support the development of a diversity of cleaner fuels with other attendant co-benefits."[10] Growth Energy sought clarification of the staff's description of the goals of the regulation for purposes of its input in the SB 617 process.[11] Lacking greater specificity or clarification, Growth Energy can only turn to the 2009 rulemaking, in which CARB quantified the "10 percent" target as being a reduction of 16 million metric tons of carbon dioxide equivalent ("MMTCO2eq") GHG emissions associated with combustion of transportation fuels in California, along with a 7 MMTCO2eq reduction in "upstream" emissions, yielding a total 23 MMTCO2eq reduction in worldwide annual GHG emissions in 2020.[12] As explained below, achieving the direct GHG emissions reduction attributed to the LCFS regulation in 2009 -- the 16 MMTCO2eq -- no longer requires the existence of the LCFS regulation.

A. Changes in the Regulatory Baseline Since 2009

The most significant development in the regulatory baseline since 2009 has been the adoption and full implementation of the federal renewable fuels standard program under the Energy Independence and Security Act of 2007, pursuant to a Final Rule adopted by the U.S.

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[10] The staff identified that goal on June 5, 2014, well after the period for preparation of SB 617 public input had begun, in response to a specific request from Growth Energy. *See* Letter from D. Bearden to K. King, May 30, 2014 (included here as Attachment 1) *and* Letter from M. Waugh to D. Bearden, June 5, 2014 (included here as Attachment 2).

[11] *See* Letter from D. Bearden to M. Waugh, June 11, 2014 (included here as Attachment 3). To date, no response to Mr. Bearden's letter of June 11, 2014, has been received.

[12] *See* ISOR at VII-1. According to the 2009 ISOR, "These reductions account for a 10 percent reduction of the GHG emissions from the use of transportation fuel." *Id.* That 10 percent target, which the CARB staff also sometimes cites, originates in Executive Order S-01-07 of January 18, 2007. *See* Executive Order S-01-07, § 1, available at http://www.arb.ca.gov/fuels/lcfs/eos0107.pdf.

Environmental Protection Agency in 2010.[13] The federal RFS program assures an adequate supply of low-cost renewable fuel for California, *i.e.*, ethanol produced from corn starch at biorefineries located mainly in the Midwest.[14] Because ethanol produced by any method from any renewable feedstock has the same physical and chemical properties when used in motor fuel, gasoline blended with 10 percent ethanol will achieve the same reduction in exhaust or "tailpipe" GHG emissions regardless of the production process or renewable feedstock used to create the ethanol. Consequently, the portion of the 16 MMTCO2eq reduction in GHG emissions from the California transportation fleet operated on gasoline can and will be obtained by virtue of the federal RFS program.[15] Oil companies will continue to buy and blend ethanol into gasoline sold in California under the federal program even if there were no LCFS program, in order to comply with the federal RFS program. The portion of the California fleet operated on diesel fuel can also achieve its part of the 16 MMTCO2eq reduction in GHG emissions by virtue of the federal RFS

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13 *See* U.S. EPA, *Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Final Rule*, 75 Fed. Reg. 14,669 (Mar. 26, 2010) .

14 The RFS program, which in its early stages was effectively non-binding on ethanol usage, has begun to cause substantial increases in biofuel production. Total production of biofuels has increased steadily over the last year and a half, reaching approximately 16 billion gallons in the 12 months through April 2014. *See* http://www.epa.gov/otaq/fuels/rfsdata/.

15 The term "fleet," as used here, includes off-road vehicles and engines in other equipment.

When the CARB staff considered the matter in 2009, it made a number of assumptions about the efficacy of the federal RFS program that need to be reconsidered. The most significant assumption, which was empirically unsupported, was that the federal program (which at the time was still under development) would provide only 30 to 40 percent of the GHG reductions that the staff predicted for the LCFS program. That assumption appears to have been based on a belief that without the LCFS regulation, only 11.3 percent of the advanced or cellulosic biofuels required nationwide by the RFS program would be consumed in California, while a substantially higher amount of those fuels would be drawn from the nationwide fuel pool to California as the result of the LCFS regulation. The advanced biofuels required by the RFS regulation that would be drawn to California by the LCFS program would have been used elsewhere in the absence of the LCFS program, leading to the same reductions in GHG emissions. To the extent that the cellulosic ethanol industry has experienced limits on achieving full commercial launch, those are national and even global economic and technical factors that the existence of the LCFS regulation has not to date, and will not in the future, be able to change or influence.

program, because the federal program results in blending biodiesel and renewable diesel into diesel fuel produced from petroleum.[16]

As for the portion of the California fleet powered in whole or in part with electricity or hydrogen, there is similarly no continuing need for the LCFS program, owing to other changes in the regulatory baseline since 2009. The Advanced Clean Cars program now assures that electricity and hydrogen will be full participants in the California transportation fuel pool. In 2009, CARB's baseline for the alternatives analysis of the LCFS regulation included the then-current version of the Board's regulations to control GHG emissions from new motor vehicles that had been adopted in 2004, and that set GHG emission standards for 2009 to 2016 model-year new vehicles, sometimes called the "Pavley standards." In addition, the baseline also included the then-current provisions of the agency's Zero Emission Vehicle ("ZEV") standards which require manufacturers offer electric and/or hydrogen fuel cell vehicles for sale in California. CARB has now adopted new-vehicle GHG standards applicable to 2017 to 2025 model-year new vehicles and has made significant revisions to the ZEV standards as part of the ACC rulemaking in 2012.[17]

[16] One reason why California is assured of receiving an adequate supply of ethanol is that ethanol for use in gasoline commands a higher price -- the so-called "California premium" -- in California than in other parts of the United States, as can be readily seen from data available under contract or license from the Oil Price Information Service ("OPIS"). While there are many reasons why the "California premium" exists, one major reason is that refineries producing finished gasoline products for the California retail market tend to have higher production costs than other refineries.

[17] In its 2009 LCFS alternatives analysis, the CARB staff assumed that manufactures would sell more electric vehicles than required by the ZEV standards, as they existed in 2009. Vehicle manufacturer compliance with the ZEV, new vehicle GHG, and criteria emission standards is determined on a "fleet-average" basis. What this means is that to the extent that manufacturers sell more ZEVs than required, they can in turn sell greater numbers of less fuel efficient or higher emitting vehicles provided that they remain in compliance on average. In addition, manufacturers that over comply can sell "credits" to manufacturers that would not otherwise be in compliance. Therefore, even if the LCFS regulation might lead to greater demand and use of electric vehicles, there would be no net reduction in GHG emissions.

CARB has also taken and is taking a number of actions to reduce GHG emissions associated with the use of diesel fuel in heavy-duty vehicles which also need to be taken into account in the baseline for the 2014 LCFS analysis. The relevant measures include California's Tractor-Trailer regulation adopted in 2008 which requires use of aerodynamic improvement devices and low-rolling resistance tires, as well as the Phase I and the soon-to-be proposed Phase II heavy-duty GHG regulations that impose specific GHG emission requirements on new heavy-duty vehicles beginning with the 2014 model-year.[18]

B. Necessary Information for Development of a Detailed Alternative Program

In addition to properly defining the baseline for the alternatives analysis, it is important to have a clear and complete picture of the revised LCFS program that the CARB staff plans to propose. In addition to full information concerning the estimated benefits of the LCFS program (both in terms of GHG reductions and in any other relevant aspect), the currently unknown elements of that program include the following:

- Updated carbon intensity values for transportation fuels that will be included in the proposed 2014 LCFS regulation.
- The detailed form of any proposed "cost-containment" provisions which could allow parties subject to the LCFS regulation to comply with the program's standards, without actually achieving the CI reductions required under the regulation.
- CARB staff's current analysis of the manner in which regulated parties will most likely attempt to comply with the proposed 2014 LCFS.

[18] In addition to ensuring that the GHG emissions reductions associated with those regulations are properly accounted for in the baseline for the 2014 LCFS, CARB staff must also ensure that they properly account for the fact that compliance with the latter regulations is determined on a manufacturer fleet average basis in order to avoid improper assignment of GHG reductions to the 2014 LCFS regulation.

- A full description of any other intended goals of the LCFS regulation, such as stimulating "fundamental" changes in the "transportation fuel pool," along with the metrics to be used to measure progress and success in meeting those other goals.[19]

Contrary to the position taken in the CARB staff's recent correspondence with Growth Energy and in related postings on the CARB website, none of those elements have been disclosed to the public at present. In addition to providing that undisclosed information concerning its analysis, the CARB staff should address the following other pertinent questions, which follow from the foregoing review of changes in the regulatory baseline since 2009:

- Does the CARB staff agree that the federal RFS program would, in the absence of an LCFS regulation, assure some level of reductions in GHG exhaust emissions from the California in-use vehicle population that is operated on gasoline? If not, why not; and if so, what would be that level of GHG emissions reductions, on an annual or some other specific basis, if the LCFS program were to be discontinued at the end of 2015?
    - Does the staff have any disagreement with the position that the federal RFS program and the "California premium" (*see* note 15 above) would cause Midwest corn ethanol producers to continue preferentially to deliver ethanol to California, and cause the California gasoline marketing sector to blend that Midwest corn ethanol into gasoline up to the current 10 percent limit, even in the absence of the LCFS regulation? If so, what are the specific reasons why the staff disagrees?
    - Does the staff believe that the LCFS regulation would result in wider usage of E85 in California than the federal RFS program would cause, and if so, what is the empirical basis for that view?
    - Would a possible need for a diesel component to an LCFS program justify an unnecessary gasoline component for an LCFS program, and if so, why?
- The 2009 regulatory analysis predicted that ultra-low-CI fuels would be available and would bring the costs of the LCFS program down to the point where the program would be cost-neutral at the consumer level, or would result in savings of up to $11 billion.[20]

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[19] *See* Air Resources Board, *California's Low Carbon Fuel Standard -- Final Statement of Reasons* (hereinafter "FSOR") 24.

[20] *See* ISOR at ES-26.

Does that remain the CARB staff's position? If not, what will be the consumer costs of the staff's proposed revised LCFS regulation, predicted annually or in some other manner? What uncertainties and assumptions affect those cost estimates?

- Are the ACC program and other vehicle-based GHG reduction programs adopted to implement AB 32 designed to obtain, and will they obtain, the maximum technologically feasible and cost effective reductions in GHG emissions from the new vehicles that are subject to those standards? (*See, e.g.*, Cal. Health & Safety Code § 38562(a).) If not, why not? With the ACC program and other non-LCFS regulations discussed above in Part II. A. now in place, would the LCFS program actually produce any incremental increase in the displacement of liquid motor vehicle fuels by electricity in ZEVs or hybrid electric vehicles or hydrogen in fuel cell vehicles? If so, what are the relevant increases, and on what assumptions do the predicted increases depend? Why would a vehicle manufacturer that over-achieved the ZEV requirement not use the credit gained from the overachievement by selling a higher-emitting conventional vehicle fleet? To what extent would the staff attribute to the LCFS program any displacement of vehicle miles traveled in conventional vehicles by vehicles powered by fuel cells, and what is the basis for that prediction?

- The CARB staff sometimes refers to Executive Order S-07-01 as a basis for maintaining the LCFS regulation. Should the requirements of Executive Order S-07-01 be reconsidered in the current rulemaking process insofar as the Executive Order called for creation of the LCFS regulation? Does Executive Order S-07-01 limit in any way CARB's discretion in adopting and enforcing measures to implement AB 32? Does AB 32 require adoption and enforcement of the LCFS regulation, if the same GHG reductions that the LCFS regulation can achieve could be achieved by other means?

- To the extent that the LCFS program is still intended to stimulate "fundamental changes in the transportation fuel pool" in California,[21] to what extent had the program succeeded in its first five years? Is achieving that objective consistent with the potential "cost reduction" mechanisms under consideration for a revised LCFS regulation? How should the Department and the public try to weigh that objective against the potential costs for California consumers and businesses in meeting that objective?

Having now presented the above questions to the CARB staff, Growth Energy believes that the staff should address them in the SRIA for the Department, or concurrently in a separate submittal to the Department made available to the public, if the staff does not intend otherwise to respond to those questions. Each question bears on the need for the LCFS regulation, the costs and benefits of the LCFS regulation, or the legal authority that would limit the analysis of regulatory

[21] *See* note 19 above.

alternatives. If the CARB staff does not believe that one or more of the above questions are relevant to the evaluation of regulatory alternatives, Growth Energy requests that the CARB staff explain why, with respect to each such question.

III. Regulatory Alternatives

The CARB regulations adopted since 2009 and the federal RFS program adequately provide for full control of the direct GHG emissions from the California vehicle fleet that the LCFS regulation may have been intended to control. In 2009, CARB claimed that the LCFS regulation would provide additional GHG reductions on a lifecycle basis; the "upstream" component of the GHG benefits attributed to the LCFS regulation in 2009 was 7 MMTCO2eq in 2020.[22]

Putting to one side the question whether CARB has legal authority to adopt and enforce a regulation to control GHG emissions occurring outside California, there are several reasons to question whether the LCFS regulation actually achieves any reduction in upstream emissions. As CARB has recognized, the LCFS regulation has to date caused "fuel shuffling" -- ethanol that might have been sold in California prior to the LCFS regulation is still being produced, and is sold somewhere else.[23] Ethanol production processes and pathways that have putatively higher upstream emissions have, at this point, neither terminated nor curtailed operations as a result of the LCFS regulation.[24] In addition, many Midwest corn ethanol biorefineries have qualified for

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22 *See* ISOR at VII-1.

23 *See* FSOR at 477 ("Without the wider adoption of fuel carbon-intensity standards, fuel producers are free to ship lower-carbon-intensity fuels to areas with such standards, while shipping higher-carbon-intensity fuels elsewhere. The end result of this fuel 'shuffling' process is little or no net change in fuel carbon-intensity on a global scale.") The "wider adoption" of LCFS-type standards to which CARB referred in the 2009 FSOR has not occurred.

24 That is not to say, however, that the LCFS regulation is not injurious to the national market in ethanol, nor neutral in its impact on lifecycle GHG emissions. By causing fuel shuffling, the LCFS regulation disrupts the national market in ethanol, imposes costs, and increases transportation-related GHG emissions. Eventually, by effectively banning Midwest corn ethanol from California (if, for example, the LCFS for 2015 established in

lower-carbon-intensity LCFS "pathways" since 2009, on a scale that the CARB staff has admitted was "not expected in 2009."[25] Moreover, the estimates of upstream emissions attributed to Midwest corn ethanol in 2009 were grossly inflated: no one, including CARB, is still prepared to defend the indirect land-use change emissions factors accepted by CARB in 2009, and the current literature demonstrates that the "science" of indirect land-use change is too unreliable to be used as a basis for regulation.[26]

To the extent there is any remaining basis for attributing upstream GHG emissions reduction benefits to the LCFS regulation, those benefits certainly do not warrant the continuation or re-adoption of the LCFS regulation. The more efficient approach would be to adjust the cap-and-trade regulation in Title 17 of the *California Code of Regulations* to account for whatever increment of GHG emissions reductions would be forgone by eliminating the LCFS regulation.[27] To the extent necessary, modifications to the cap-and-trade regulation would be

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2009 were to be enforced), the LCFS regulation will leave California with no commercially viable method of complying with the standard; the staff appears to recognize this problem to some extent, with the currently ill-defined "cost reduction" features that it plans to propose. *See* Air Resources Board, *Low Carbon Fuel Standard Re-Adoption Concept Paper* (March 2014) at 6-7. The reduction in nationwide demand for Midwest corn ethanol will then also impose serious economic harm on the Midwest ethanol industry.

[25] *See* 2011 Program Review at 169. The Midwest ethanol production facilities that have qualified for lower-carbon-intensity LCFS pathways have not done so through modifications in their production processes intended to obtain those special LCFS pathways: they have a competitive incentive to increase efficiency, and would have done increased their efficiency in the absence of the LCFS regulation. A Growth Energy member has demonstrated this point in the ongoing *Rocky Mountain* litigation involving some aspects of the LCFS regulation. *See* Declaration of Erin Heupel, P.E. (included here as Attachment 6) ¶¶ 5-6. Notably, in the *Rocky Mountain* litigation, CARB offered no competent evidence to the contrary. As Ms. Heupel also demonstrated, the specific features of the LCFS regulation will eventually force even the highest-efficiency Midwest corn production facilities out of the California market. *See id.* ¶¶ 9-11.

[26] The CARB staff has begun to revise and to reduce the indirect land-use change emission factors that were included in the 2009 LCFS regulation. *See* letter from G. Cooper to K. Sideco, April 9, 2014, available at http://www.arb.ca.gov/fuels/lcfs/regamend14/rfa_04092014.pdf. It remains Growth Energy's position that the modeling methods used by CARB to generate indirect land-use change values are too unreliable for use in a regulation intended to comply with AB 32. *See* Letter from D. Bearden to J. Goldstene, May 10, 2010 (included here as Attachment 4).

[27] In 2009, CARB received substantial comments on the relative inefficiency of the LCFS approach from one of its independent peer reviewers, who urged that CARB consider a cap-and-trade alternative. *See*, e.g., FSOR at 24 (review by Dr. John Reilly); *see also id.* (summarizing Dr. Reilly's review as stating, "The economic analysis

simple and straightforward. Initially, CARB should determine what, if any, upstream GHG reductions should be attributable to the LCFS regulation, using a scientifically reliable process. CARB would also need an appropriate estimate of the total GHG emissions expected from the use of gasoline and diesel fuel in 2020. A CARB emissions forecast prepared in 2010[28] indicates that total GHG emissions from gasoline and diesel fuel use in California are expected to be approximately 175 million metric tons in 2020 under business as usual conditions. Assuming that the generally required 22 percent reduction in emissions in 2020 under the cap-and-trade program[29] applies to gasoline and diesel fuel use, total 2020 emissions without the LCFS program would be about 135 million metric tons.

Continuing the analysis, and by way of example, suppose that the cap-and-trade regulation had to cover the entire annual 16 MMTCO2eq of GHG emissions that the CARB staff identified as the benefit of the LCFS regulation for 2020. That level of GHG control could be achieved by amending the cap-and-trade regulations to require providers of gasoline and diesel fuel to submit 151 (135+16) million metric tons of allowances – or in other words requiring gasoline and diesel fuel suppliers to surrender 1.11 (151/136) allowances for every ton of GHG emissions they report from the fuels they supply.[30]

[for the LCFS regulation] was done incorrectly. It does not meet [the] technical standards of economics. The baseline assumptions are mutually inconsistent, and if these assumptions were executed in a proper model it would show that the LCS was unnecessary.") CARB stated in 2009 that it would consider the role of cap-and-trade further in addressing the objectives of the LCFS program once the cap-and-trade regulations were completed. *See* FSOR at 452.

28 *See* Air Resources Board, "California GHG Emissions -- Forecast 2008-2020 (updated Oct. 28, 2010), available at http://www.arb.ca.gov/cc/inventory/data/tables/2020_ghg_emissions_forecast_2010-10-28.pdf

29 This is based on the general percentage reduction requirements established by CARB for total allowances issued. *See* Air Resources Board, "Overview of ARB Emissions Trading Program (October 2011), available at http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf

30 The cap-and-trade regulation already begins to take effect for the gasoline and diesel fuel marketing sector in 2015.

The modifications to the existing text of the cap-and-trade regulation would be minor and limited to section 95852(d) of the regulation.[31] Further, the CARB staff at its discretion could also create a compliance offset program in order to incentivize low- carbon intensity fuels similar to those in place which incentivize other innovative GHG reduction strategies.[32] Insofar as one goal of the APA is to eliminate unnecessary regulation, this approach would well-serve the goals

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[31] Thus, the text of section 95852(d), with the modification shown in italics, and assuming that the full 10 percent GHG emission reduction attributed to the LCFS regulation would be covered by cap-and-trade, would provide as follows:

> Suppliers of RBOB and Distillate Fuel Oils. A supplier of petroleum products covered under sections 95811(d) or 95812(d) has a compliance obligation *equal to 1.x allowances* for every metric ton CO_2e of GHG emissions included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned that would result from full combustion or oxidation of the quantities of the following fuels that are removed from the rack in California, sold to entities not licensed by the California Board of Equalization as a fuel supplier, or imported into California and not directly delivered to the bulk-transfer/terminal system as defined in section 95102 of MRR, except for products for which a final destination outside California can be demonstrated:

(1) RBOB;
(2) Distillate Fuel Oil No. 1; and
(3) Distillate Fuel Oil No. 2.

> *The value of "x" above will be established by Executive Officer by the prior October 31 for each year beginning with 2015 to ensure that actual GHG emissions from the use of RBOB and Distillate Fuel Oil No. 1 and Distillate Fuel Oil No. 2 are reduced to the level that would have been achieved had the Carbon Intensity of those fuels been reduced according to the following schedule relative to 2010.*

Required Carbon Intensity Reduction Relative to 2010	
Year	Reduction
2015	2.7%
2016	3.7%
2017	5.2%
2018	6.7%
2019	8.2%
2020	10.0%

As illustrated above for 2020, the value of "x" would be 0.11 and the compliance obligation for suppliers of gasoline and diesel fuels would be 1.11 times the number of tons of CO_2e emissions reported.

[32] *See* Air Resources Board, "Climate Change Programs -- Compliance Offset Program" (updated June 11, 2014), available at http://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm

of the APA. By eliminating the LCFS regulation, CARB would also free the California transportation fuel sector from continuing uncertainty about the availability and cost of ultra-low-carbon-intensity alternative fuels necessary for future compliance with the LCFS. As the Western States Petroleum Association ("WSPA") has stated:

> The LCFS, as envisioned by Governor Schwarzenegger in his Executive Order and as developed by the ARB, is infeasible. ... [S]taying the course now could result in disruptions in the transportation fuels markets. ... A successful fuels policy must protect against fuel supply disruptions, severe job losses in the state's refining industry and unacceptable economic harm to California and its citizens.[33]

While Growth Energy believes that its proposal has sufficient merit without endorsement by other organizations, the concerns expressed by WSPA are important. One benefit of the change that Growth Energy is proposing, and a benefit that is particularly important to Growth Energy and the enterprises it represents, is that elimination of the LCFS regulation would eliminate a major conflict between regulations adopted by California and the federal RFS program, a conflict that will only increase if the LCFS regulation is re-adopted.

In considering Growth Energy's proposal, and in addition to the questions presented in Part II of this submittal, the CARB staff should in the SRIA address the following questions:

- The CARB staff's May 23, 2014, notice soliciting public input for the SRIA sought "alternative LCFS approaches." (See Attachment 5.) Does the CARB staff believe the alternatives analysis for the SRIA and public submittals related to the SRIA must be confined to regulatory alternatives that include or would preserve in some form the LCFS regulation? If so, what is the basis for such a limitation?

- Other than emissions created in generating electricity for delivery in California, does AB 32 give CARB the authority to regulate upstream emissions occurring outside California, or to account for upstream emissions occurring outside

[33] The reference is to Executive Order S-01-07, with its "10 percent" by 2020 goal, which according to the CARB staff remains the target for the LCFS regulation. *See* Letter from G. Grey to K. Sideco, June 13, 2014 at 2, available at http://www.arb.ca.gov/fuels/lcfs/regamend14/wspa_06132014.pdf. WSPA has also stated that modification of the LCFS program through "cost reduction" provisions would "simply penalize fuel suppliers for not meeting an infeasible standard." *See* Letter from C. Reheis-Boyd to K. Sideco, April 11, 2014 at 10, available at http://www.arb.ca.gov/fuels/lcfs/regamend14/wspa_04112014.pdf.

California in adopting regulations to meet the statewide greenhouse gas emissions limit? (*See* Cal. Health & Safety Code § 38505(m), (n); 38562(a).) If AB 32 authorizes CARB to regulate or consider out-of-state GHG emissions attributed to ethanol production, does AB 32 also authorize CARB to address those emissions through the cap-and-trade regulation?

- Can the California cap-and-trade regulations be modified to provide the same numerical reductions in GHG emissions as the LCFS regulation? If not, why not?

- If the CARB staff is concerned that the state measures to control GHG emissions and the federal RFS program might not be fully implemented and enforced at some time in the future, would adoption of a revised LCFS regulation as a "backstop" measure, to be implemented only if those other programs are not meeting defined objectives, address that concern? If not, why not?

- If the CARB staff believes some regulated parties might prefer to comply with a revised LCFS regulation rather than a modified cap-and-trade regulation, could that issue be addressed by including a revised LCFS as a part of a regulatory alternative (with appropriate opt-in provisions) that would be an option for parties that did not wish to comply with a modified cap-and-trade regulation?

- What are the current and expected future levels of resources at CARB, in terms of personnel and other resources, that are allocated to the LCFS regulation? What would be the budgetary impact for CARB if the LCFS program were eliminated? What would be the budgetary impact for CARB caused by the change in the cap-and-trade regulation proposed here?

- To the extent the CARB staff would attribute other beneficial impacts, different from GHG emissions reductions, to the LCFS regulation, to whom do those benefits accrue? With regard to those other beneficial impacts, are California consumers benefitted and, if so, how and to what extent? With regard to those other beneficial impacts, are California businesses benefitted and if so, how and to what extent? Do those other beneficial impacts justify or support continuation of the LCFS regulation, and if so, what is the basis for CARB's authority to adopt and enforce the LCFS regulation to obtain those benefits? If those other beneficial impacts include the possibility that sources for alternative fuels will be increased or diversified, are there any peer-reviewed or other studies that support such a proposition? If not, what is the staff's basis for attributing such benefits to the LCFS regulation? Could those benefits be realized through the development of a compliance offset program under the cap-and-trade regulation?

As with the questions presented in Part II, the CARB staff's responses to these questions are important in understanding its evaluation of Growth Energy's proposal. If the CARB staff does not believe that one or more of the above questions are relevant to the evaluation of regulatory alternatives, Growth Energy requests that the CARB staff explain why, with respect to each such question.

IV. Next Steps

As noted at the outset of this submittal, Growth Energy's analysis of alternatives to the LCFS regulation can be no more detailed than the available information about the staff's intended revised LCFS regulation. If CARB does nothing further to facilitate the public input into the SB 617 process for use in the SRIA, it will not have substantially complied with the APA as amended by SB 617 and implemented in the Department's regulations.

In the CARB staff's first notice that it was ready to receive public input on regulatory alternatives, published on May 23, 2014, the staff set a deadline for that input of June 6, 2014 -- nine business days later. The staff indicated in that notice that the public should, among other things, "submit the quantities of low-CI fuels used each year" in the proposed alternative to the LCFS regulation, "as well as the associated cost and benefit information, and their sources." [34] According to the May 23 notice, that information was needed "to enable comparison of economic impacts."[35] The May 23 notice stated that the objective for public input should be to provide "alternative LCFS approaches," meaning "any approach that may yield the same or greater benefits than those associated with the proposed regulation, or that may achieve the goals at lower cost."[36]

The "proposed regulation" to which the May 23 proposal referred (i) had not been provided to the public for review as of May 23, nor (ii) has it been provided at any time since

[34] *See* Attachment 5.

[35] *Id.*

[36] *Id.*

May 23.[37] The May 23 notice was not accompanied by any information that provided the CARB staff's own prediction of "the quantities of low-CI fuels [that would be] used each year" under the CARB staff's proposed regulation, nor the benefits that the CARB staff attributed to the LCFS regulation. Growth Energy requested that the CARB staff give the public the information needed to prepare a complete SB 617 submission and requested that the public be given additional time to prepare SB 617 analyses after the necessary information was released.[38]

The CARB staff responded by extending the deadline for public submittals that would be addressed in the SRIA to June 23, 2014 (31 days after the May 23 notice), but did not provide any of the information requested by Growth Energy and needed to provide the type of input sought in the May 23 notice, and necessary under the Department's SB 617 regulations. Instead, the staff referred to the GHG emissions reductions targeted in the 2009 rulemaking, to a March 2014 "Concept Paper" that discussed the staff's approach to revision of the LCFS regulation, and to material provided to the public in connection with regulatory workshops held in ARB's offices.[39] The March 2014 Concept Paper raises more questions about the staff's approach than it answers: it included, for example, a general description of two different "cost reduction" concepts without indicating how either of them would work, how they would reduce costs, or how they would affect the GHG emissions reduction benefits of the LCFS program. If the March 2014 Concept Paper provided a basis for preparing SB 617 submittals, then there is no reason why the CARB staff should have waited until May 23 to solicit public input under the Department's regulations. Had the staff informed the public when it released the Concept Paper

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[37] The CARB staff has released some draft regulatory text for their proposed revised LCFS, but that partial text does not include, for example, the "cost reduction" feature intended for the new regulation, nor the carbon intensity values to be assigned to each alternative fuel.

[38] *See* Attachment 1.

[39] *See* Attachment 2.

and discussed the Concept Paper at one of its March 2014 regulatory workshops that the Concept Paper was intended to provide a basis for SB 617 input, Growth Energy (and perhaps other stakeholders) would have pointed out at that time that the Concept Paper was inadequate for that purpose; in that event, perhaps the CARB staff would have been able to provide the necessary information for public input into the SRIA.

The materials provided in connection with the regulatory workshops -- including the partial regulatory text released on May 28, after the staff had launched the public input process -- likewise do not provide the necessary information for detailed public submittals consistent with SB 617 and the Department's regulations. Growth Energy has studied those materials carefully, and with the greatest respect, would challenge the CARB staff to indicate where in those materials the staff identifies GHG emissions reduction targets for a revised LCFS regulation; where the staff identifies any other putative benefits of the LCFS regulation; and where in those materials the staff provides specific and concrete information about the impact of the "cost reduction" concepts on the quantities of alternative fuels that would be used in order to comply with the revised LCFS regulation, or permits a quantification of costs and benefits of a revised LCFS regulation that includes a cost-reduction feature.

Finally, it is important to address comments by the CARB staff at one recent workshop, which suggested that the timing of the current regulatory effort has been affected by the Board's need to comply with the mandate in litigation under the APA and the California Environmental Quality Act ("CEQA").[40] In that litigation, the Superior Court has allowed CARB all the time

[40] The case is *POET LLC et al. v. California Air Resources Board*, Case No. 09 CE CG 04659 (Sup'r Ct., Fresno County). The Writ of Mandate in that proceeding does not require CARB to commence or conclude rulemaking by a particular date, but to proceed in good faith without delay. The Writ of Mandate was issued more than six months ago, by which time CARB presumably knew that it had to comply with the Department's SB 617 regulations.

that the Board has requested in order to comply with the mandate. If CARB needs more time in order to conduct the SB 617 process in a manner that allows sufficient time for effective public input into the preparation of an SRIA, CARB should so inform the Superior Court. (Notably, in its filings with the Superior Court, CARB has not adverted to SB 617 or the Department's implementing regulations.) In addition, the CARB staff would surely agree that even before issuance of the mandate in that litigation, it was aware that it had major program review obligations for the LCFS regulation in 2014.[41] Particularly in light of those program review obligations, the CARB staff's inability to provide more information now to the public, needed to participate fully in the SB 617 process, seems inexcusable.

Against that backdrop, Growth Energy urges the CARB staff to reconsider its present approach to the SB 617 process, and specifically the staff's approach to obtaining public input for the SRIA. As the staff might expect, if one response to Growth Energy's proposed regulatory

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[41] In 2009, when it first adopted the LCFS regulation, the Board directed the CARB staff to conduct and to present by January 1, 2015 a "review of implementation of the LCFS program" that was to "include, at a minimum, consideration of the following areas:

"(1) The LCFS program's progress against LCFS targets;
"(2) Adjustments to the compliance schedule, if needed;
"(3) Advances in full, fuel-lifecycle assessments;
"(4) Advances in fuels and production technologies, including the feasibility and cost-effectiveness of such advances;
"(5) The availability and use of ultralow carbon fuels to achieve the LCFS standards and advisability of establishing additional mechanisms to incentivize higher volumes of these fuels to be used;
"(6) An assessment of supply availabilities and the rates of commercialization of fuels and vehicles;
"(7) The LCFS program's impact on the State's fuel supplies;
"(8) The LCFS program's impact on state revenues, consumers, and economic growth;
. . .
"(12) Significant economic issues; fuel adequacy, reliability, and supply issues; and environmental issues that have arisen; and
"(13) The advisability of harmonizing with international, federal, regional, and state LCFS and lifecycle assessments."

17 C.C.R. § 95489(a).

alternative is that Growth Energy's proposal lacks a detailed comparison with the costs, benefits, and cost-effectiveness of the staff's proposal in the SRIA, Growth Energy will attribute its lack of specificity to the staff's failure to provide the information needed to offer a more specific regulatory analysis. Because this is one of the first major rulemakings at CARB that is required to comply with SB 617 and the Department's SB 617 regulations, it is also important for the Department to take a proactive role in providing guidance to CARB, the stakeholders, and other members of the public interested in the LCFS program.

Respectfully submitted,

GROWTH ENERGY

Appendix G

GHG Emissions Impact of Fuel Shuffling Due to California Low Carbon Fuel Standard

AIR, Inc.

February 14, 2015

The California LCFS requires a 10% reduction in carbon intensity between 2010 and 2020 for fuels sold in California. Much of the GHG emission reductions come from biofuels that are mixed with either gasoline or diesel fuel. Biofuel production has increased in the US and elsewhere. There are two possible scenarios for where the biofuels are used. In one scenario, where the LCFS is not in effect, the carbon intensity of biofuels used is approximately the same inside and outside of California. Biofuels are generally used where they are produced, and transportation emissions for biofuels are minimized. For example, ethanol from corn is used in the US, and ethanol from Brazil is used in Brazil. In a second scenario where the LCFS is in effect, the LCFS causes lower carbon intensity biofuels to flow into California for use there. All other biofuel production, which may have slightly higher average carbon intensity than the average in California, is used outside of California. In this second case, global GHG emissions can actually increase, because the same quantity of biofuel is used in either case, but in the second case, transport GHG emissions are higher, because biofuels are not being used where they were produced. This overall concept is referred to as fuel shuffling.

The LCFS requirement causes fuel shuffling, because the regulation is expected to result in increasing amounts of cane ethanol from Brazil to be used in California. This is shown in Table B-18 below, which shows volumes of different types of ethanol that ARB expects under one of the possible compliance scenarios (see Table B-18 of Appendix B to the ISOR). In California corn and related ethanol (sorghum) declines, while other fuels, notably cane ethanol, increases. However, while corn ethanol declines in California, it does not decline elsewhere, but increases with the RFS and with exports. Thus, worldwide there is no change in GHG emissions worldwide just because corn ethanol declines in California. However, the shift from corn ethanol to cane ethanol causes an increase in ethanol transportation and distribution emissions because of the difference in transportation distances between the Midwest to California and Brazil to California.

Table B-18. Illustrative California Reformulated Gasoline Oxygenates and Substitute Fuels through 2020							
Fuel	2014	2015	2016	2017	2018	2019	2020
Corn and related ethanol, mmg	1,400	1,350	1,250	1,175	1,000	925	875
Cane and sugar ethanol, mmg	120	170	240	290	410	460	510
Cellulosic ethanol, mmg	0	0	5	15	50	75	100
Renewable gasoline, mmg	0	0	0	0	5	15	25
Hydrogen, mmgGGE	0.03	0.4	1	2	4	5	7
Electricity for LDVs, mmgGGE	9	14	19	24	31	40	51

We first estimated the GHG emission impact of increased transportation emissions with CaGREET2.0. We used distances and modes of transportation provided in CAGREET2.0. Results are shown in Table 1 below. For this analysis we assume a 390 million gallon per year increase in cane ethanol and a corresponding decrease in corn ethanol, which is the difference in the 2020 cane ethanol value (510 million gallons per year) and the 2014 value (120 million gallons per year) in Table B-18 above. Results show a 145,000 ton per year increase in GHG emissions, which is the fuel shuffling effect, assuming GREET cane ethanol transport emissions are correct.

Table 1. Extra Transport GHG Emissions from Brazil Sugar Cane Ethanol								
	Emission Factors (grams/MMBTU of Fuel Transported)			Emissions		Emissions, CO2e		
Pollutant	Brazil to LA/Long Beach *	Midwest to CA **	Difference	Billion Grams	GWP	Billion Grams	Short Tons	gCO2e/ MJ
VOC	5.109	1.321	3.788	0.113	3.12	0.351	387	0.0112
CO	12.221	4.428	7.793	0.232	1.57	0.365	402	0.0116
CH4	7.896	3.051	4.845	0.144	25.	3.605	3,974	0.1148
N2O	0.141	0.051	0.090	0.003	298.	0.801	882	0.0255
CO2	6,577.633	2,326.555	4,251.078	126.549	1.	126.549	139,496	4.0292
					Totals:	131.671	145,142	4.1923

*Brazil to LA/Long Beach includes: Pipeline, Rail, Truck, Ocean Tanker, and USTruck.
**Midwest to CA includes: Rail, Truck, and Truck.

A report by (S&T)², however, shows that the CaGREET2.0 transport emissions for cane ethanol could be quite low. [1] We used the same transport distances from Table 1 and information from the (S&T)² report to estimate emissions, both with and without a backhaul included. Results are in Table 2 (details shown in Attachment 1) and show that the fuel shuffling emissions are between 375,000 and 716,000 tons of GHG per year.

Table 2. Increase in Fuel Shuffling GHG Emissions	
Case	Extra Fuel Shuffling Emissions (GHG, tpy)
Ca GREET2.0	132,000
(S&T)², no backhaul	375,000
(S&T)², with backhaul	716,000

[1] *REVIEW OF THE SUGAR CANE ETHANOL PATHWAYS IN CA-GREET 2.0,* (S&T)² for Growth Energy, February 2, 2015.

Attachment 1

Details of Fuel Shuffling Estimates for (S&T)² Transport Emissions

Without Backhaul

Pollutant	Emission Factors (grams/MMBTU of Fuel Transported) Brazil to LA/Long Beach *	Midwest to CA **	Difference	Emissions Billion Grams	GWP	Emissions, CO2e Billion Grams	Short Tons	gCO2e/ MJ
VOC	11.288	1.321	9.967	0.297	3.12	0.925	1,019	0.0294
CO	26.352	4.428	21.924	0.653	1.57	1.026	1,131	0.0327
CH4	15.595	3.051	12.544	0.373	25.	9.336	10,291	0.2972
N2O	0.297	0.051	0.246	0.007	298.	2.181	2,405	0.0695
CO2	13,289.690	2,326.555	10,963.134	326.358	1.	326.358	359,748	10.3910
					Totals:	339.826	374,594	10.8198

*Brazil to LA/Long Beach includes: Pipeline, Rail, Truck, Ocean Tanker, and USTruck.
**Midwest to CA includes: Rail and two Trucks.

With Backhaul

Pollutant	Emission Factors (grams/MMBTU of Fuel Transported) Brazil to LA/Long Beach *	Midwest to CA **	Difference	Emissions Billion Grams	GWP	Emissions, CO2e Billion Grams	Short Tons	gCO2e/ MJ
VOC	20.483	1.321	19.162	0.570	3.12	1.778	1,960	0.0566
CO	47.382	4.428	42.953	1.279	1.57	2.009	2,215	0.0640
CH4	27.054	3.051	24.003	0.715	25.	17.863	19,691	0.5688
N2O	0.529	0.051	0.478	0.014	298.	4.236	4,670	0.1349
CO2	23,278.251	2,326.555	20,951.696	623.705	1.	623.705	687,517	19.8584
					Totals:	649.592	716,052	20.6826

*Brazil to LA/Long Beach includes: Pipeline, Rail, Truck, Ocean Tanker, and USTruck.
**Midwest to CA includes: Rail and two Trucks.

Appendix H

Appendix H

Impact of the LCFS on Global Climate

A quantitative modeling analysis was conducted to assess the impact of LCFS carbon emission reductions on global climate change.

Climate Model Summary – The effect of the LCFS ISOR estimates of CO_2 emissions reductions attributable to the proposed regulation were modeled using version 5.3 of a coupled, gas-cycle/climate model known as MAGICC (Model to Assess Greenhouse-gas Induced Climate Change). MAGICC has been the primary model used by the Intergovernmental Panel on Climate Change (IPCC) to produce projections of future global-mean temperature and sea level rise. Technical and user manuals explaining the model in more detail are publicly available.[1]

Version 5.3 is the latest version of MAGICC and was updated from version 4.1 to be consistent with the IPCC Fourth Assessment Report, Working Group 1 (AR4).[2] (Version 4.1 uses the earlier IPCC Third Assessment Report, Working Group 1 (TAR) climate couplings.) Updates reflected in MAGICC version 5.3 include:

- Climate sensitivity estimates updated based on AR4;
- Revised climate forcing values consistent with AR4;
- Updated carbon cycle modeling and CO_2 concentration stabilization scenarios;
- More realistic sea level rise projection method; and
- Minor "balancing" revision to methane and nitrous oxide budgets.

For purposes of this analysis, the updated climate sensitivity estimate from AR4 is the most noteworthy. The default climate sensitivity for a doubling of CO_2 has been upwardly revised from 2.6°C to 3.0°C in MAGICC version 5.3.

The key parameters for the MAGICC v5.3 modeling were as follows:

a) "mid"-level response for the carbon cycle model,
b) carbon cycle climate feedbacks set to "on,"
c) "mid"-level response for aerosol forcing,
d) 3.0° C sensitivity for doubled CO_2,
e) "variable" thermohaline circulation,
f) vertical oceanic diffusion coefficient set to "2.3 cm^2/s," and
g) "mid"-level ice melt sensitivity.

[1] T.M.L. Wigley, "MAGICC/SCENGEN 5.3: User Manual," National Center for Atmospheric Research, Colorado, September 2008.
[2] The IPCC released its Fifth Assessment Report (AR5), in October 2014. The MAGICC model has not yet been updated to reflect AR5.

Again the 3.0° C sensitivity to doubled CO_2 is consistent with the assumptions used in the IPCC AR4 report, which is based on the assumption that the surface temperature record accurately reflects the effect of greenhouse gas concentrations on ambient temperatures. Explanations of the other parameters are available in the above-referenced user manual.

<u>Emission Inputs</u> – The baseline case assumed a future in which fossil fuels will continue to be consumed in a "business as usual" manner, but with new sources of energy mixing in to supply a balance of non-carbon emitting sources. This baseline emissions case (named A1B-AIM) produces total climate forcing in 2005 that most closely approximates that in IPCC AR4 (A1B=1.596 W/m^2, AR4=1.6 W/m^2). Two different alternative scenarios were run to evaluate the potential effect of the proposed LCFS as summarized below:

1. *LCFS-CA:* This scenario applied the CARB LCFS ISOR estimated reduction in CO_2 emissions from 2020 (20.7 MMT[3] CO_2e). These reductions were held constant on a relative basis from 2020 through 2050.

2. *LCFS-US:* This second scenario assumed the reductions estimated in the LCFS ISOR would be increased by a factor of 8.9 to scale the California reductions to the entire U.S. based on California vs. entire U.S. transportation source CO_2 emission estimates published by the U.S. Energy Information Administration (EIA).

Table 1 summarizes the baseline global fossil fuel CO_2 emissions by calendar year from the AR4-A1B-AIM reference case contained in the MAGICC v5.3 emissions scenario library. The emission units for fossil CO_2 are petagrams (10^{15} grams) as noted at the bottom of Table 1. As shown in Table 1, baseline emissions under the AR4 A1B-AIM reference case are projected to rise steadily from 1990 through 2050, with 2050 emissions roughly 2.7 times higher than those in 1990.

Table 1
Baseline Scenario
Global Fossil Fuel CO_2 Emissions (Pg C[a])

Calendar Year	Annual Emissions
1990	5.991
2000	6.896
2010	9.680
2020	12.122
2030	14.011
2040	14.945
2050	16.009

[a] Petagrams of carbon; 1 petagram = 10^{15} grams

[3] MMT = million metric tons (1 metric ton = 1,000 kilograms or 1,000,000 grams)

Emissions under the LCFS-CA and LCFS-US scenarios were calculated from these baseline estimates as follows. First, the CARB ISOR LCFS emission reductions in 2020 (20.7 MMT CO_2e) were converted to "petagram carbon" units for input into MAGICC as follows:

$$20.7\ MMTCO2e \times \frac{12.01\ g/mole\ C}{44.01\ g/mole\ CO2} \times \frac{1\ Pg}{10^3\ MMT} = 5.65 \times 10^{-3}\ Pg\ C$$

This reduction in 2020 emissions estimated in the CARB ISOR represents a 0.0047% decrease ($5.65\times10^{-3}/12.112$ Pg C) in global fossil CO_2 emissions relative to the 2020 baseline. Since the ISOR reductions are expressed on a CO_2 equivalent basis, they were applied to the fossil fuel carbon emission estimates in MAGICC (although the model also includes emission estimates for other GHG compounds.)

In applying this LCFS reduction beyond 2020, out to 2050, two approaches were considered: 1) using the same absolute reduction (5.65×10^{-3} Pg C) for each future year; and 2) applying the same relative 2020 reduction (0.0466%) in each future year. The relative reduction approach produced nominally greater reductions (i.e., lower emissions) in future years. Thus, the relative reduction-based emissions were used in the climate modeling.

These California LCFS emission reductions were extrapolated to the second scenario representing nationwide LCFS adoption based on a scaling multiplier developed from EIA estimates of calendar year 2011 transportation sector CO_2 emissions by individual state.[4] EIA estimated 2011 transportation sector emissions of 199.3 and 1,781.9 $MMTCO_2$ in California and the entire U.S., respectively. Thus a scaling factor of 8.94 was developed from this ratio (1781.9÷199.3). This scaling factor was then used to conflate the California LCFS reductions from the ISOR to the entire U.S. For example in 2020, U.S. LCFS reductions were calculated as follows:

LCFS-CA Relative Reduction × Scaling Factor × 2020 Global Emissions, or
0.0466% × 8.94 × 12.122 Pg C = 0.051 Pg C reduction in 2020 CO_2 emissions

Table 2 presents a comparison of the resulting global emission estimates input to the MAGICC model for the baseline case and each of the two LCFS reduction analysis scenarios. Note that these values are emissions, not LCFS reductions (which are represented by the difference between the baseline and scenario emissions in the table).

[4] U.S. Energy Information Administration (EIA), 2011 State energy-related carbon dioxide emissions by sector, http://www.eia.gov/environment/emissions/state/analysis/.

Table 2 Comparison of Baseline and LCFS Reduction Scenario Annual Emissions (Pg C) Used in MAGICC Modeling			
Calendar Year	Baseline (A1B-AIM)	LCFS in California	LCFS in Entire U.S.
1990	5.991	5.991	5.991
2000	6.896	6.896	6.896
2010	9.680	9.680	9.680
2020	12.122	12.116	12.071
2030	14.011	14.004	13.953
2040	14.945	14.938	14.883
2050	16.009	16.002	15.942

The highlighted cells in Table 2 denote those years and emissions that reflect LCFS reductions relative to baseline estimates.

Climate Modeling Results – Table 3 shows modeled changes in ambient temperature from a 1990 baseline temperature for each case. As shown in the table, the baseline case produces an estimated increase of 0.9952°C in calendar year 2050 over the 1990 baseline. The addition of the LCFS standard is estimated to reduce this temperature increase by two ten-thousandths of a degree (0.0002). Assuming roughly nine times greater reductions to reflect LCFS implementation throughout the U.S., the temperature increase is reduced by 2.0 thousandths of a degree (0.0020).

Table 3 MAGICC Version 5.3 Model Results (°C) for Calendar Year 2050		
Scenario	Temperature Change from 1990 Baseline	Change Due to LCFS
Baseline (IPCC Case A1B)	0.9552	n.a.
Low Carbon Fuel Standard in California	0.9550	0.0002
Low Carbon Fuel Standard throughout U.S.	0.9532	0.0020

Appendix I

STATE OF CALIFORNIA

BEFORE THE AIR RESOURCES BOARD

Declaration of James M. Lyons

I, James Michael Lyons, declare as follows:

1. I make this Declaration based upon my own personal knowledge and my familiarity with the matters recited herein. It is based on my experience of nearly 30 years as a regulator, consultant, and professional in the field of emissions and air pollution control. A copy of my résumé can be found in Attachment A.

2. I am a Senior Partner of Sierra Research, Inc., an environmental consulting firm located at 1801 J Street, Sacramento, California owned by Trinity Consultants, Inc. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private industry clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California at the Mobile Source Division of the California Air Resources Board (CARB).

3. During my career, I have worked on many projects related to the following areas: 1) the assessment of emissions from on- and non-road mobile sources, 2) assessment of the impacts of changes in fuel composition and alternative fuels on engine emissions including emissions of green-house gases, 3) analyses of the unintended consequences of regulatory actions, and 4) the feasibility of compliance with air quality regulations.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, factors affecting emissions from diesel vehicles, evaporative emission control system design and function, as well as combustion chamber system design. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and for the United States Environmental Protection Agency. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality.

5. This Declaration summarizes the results of analyses I have performed regarding CARB staff's analysis of different aspects of the re-adoption of the Low Carbon Fuel Standard (LCFS) Regulation and Regulation on the Commercialization of Alternative Diesel Fuels (ADFs) as an independent expert for Growth Energy. If called upon to do so, I would testify in accord with the facts and opinions presented here.

6. Based on a review of the Initial Statement of Reasons (ISOR) for the LCFS regulation and the associated appendices, including the draft Environmental Analysis, it is clear that CARB staff failed to quantify the GHG emission reductions associated with the LCFS regulation itself. Rather, staff notes that the GHG reduction estimates provide are inflated as the result of the "double counting" of GHG reductions due to other regulatory programs.

7. Further, this review shows that CARB staff failed to perform a complete analysis of the potential air quality impacts associated with the LCFS regulation. More specifically, CARB staff's air quality analysis fails to quantitatively assess the impact of the LCFS and ADF on all emission sources that could be affected nor does it consider all of the pollutants for which emission changes might occur. A summary of the review is Attachment B to this declaration.

8. CARB staff rejected a proposed alternative to the LCFS regulation submitted by Growth Energy claiming that it will likely result in the same environmental benefits, but not ensure a transition to lower carbon intensity fuels that CARB staff claims is the main goal of the LCFS regulation. As discussed in detail in Attachment C to this declaration, CARB staff failed to perform any analysis of the Growth Energy Alternative and has provided no support for this finding. Because the Growth Energy Alternative provides greater environmental benefits and is expected to cost less than the LCFS regulation, it must be adopted by CARB instead of the LCFS regulation.

9. As part of the development of the ADF regulation, CARB staff examined the impacts of the proposed regulation on emissions of pollutants including oxides of nitrogen (NOx) emitted from heavy-duty diesel engines operating on blends of diesel fuel and biodiesel.

10. NOx emissions directly affect atmospheric levels of nitrogen dioxide, a compound for which a National Ambient Air Quality Standards (NAAQS) has been established. NOx emissions are also precursors to the formation of ozone and particulate matter, which are also pollutants for which NAAQS have been established. Areas of the South Coast and San Joaquin Valley air basins are in extreme and moderate non-attainment of the most recent ozone and fine particulate standards, respectively.

11. In the Initial Statement of Reasons (ISOR) for the ADF regulation and its' appendices, CARB staff summarized its analysis of increases in NOx emissions from heavy-duty diesel vehicles over the period from 2014 through 2023. The results of the staff's analysis are most clearly summarized in Table B-1 of Appendix B of the ISOR. This table shows that staff estimate that biodiesel use allowed under the ADF regulation will increase NOx emissions by 1.35 tons per day in 2014 and that the magnitude of this emission increase will drop to 0.01 ton per day by 2023.

12. I have performed a review of the staff's assessment of the NOx emission impacts of biodiesel use allowed under the ADF regulation presented in ISOR and its' appendices and find it to be fundamentally flawed such that it is not reliable. First, the bases for total diesel NOx emissions inventory is not described in the ISOR or in other

documents in the record. Second, CARB staff incorrectly assumes that the use of biodiesel in "New Technology Diesel Engines (NTDEs)" equipped with exhaust aftertreatment devices to lower NOx emissions will not lead to increased NOx emissions. Third, CARB staff incorrectly apply ratios of on-road vehicle travel by NTDEs from the now obsolete EMFAC2011 model to account for the amount of biodiesel used in all NTDEs including those found in non-road equipment. Fourth, to assess the overall impact of the ADF regulation on NOx emissions, CARB incorrectly subtracts NOx reductions resulting from the use of "renewable diesel fuel" from increases in NOx emissions resulting from the use of biodiesel.

13. In addition, I have performed a very conservative assessment of the NOx emission impacts of biodiesel use under the ADF that uses the latest CARB emissions models and corrects the flaws in the staff analysis, a summary of which is attached. The results of this assessment indicate that NOx increases from biodiesel will be much larger than those estimated by CARB staff and that the magnitude of the impacts will not decline over time as forecast by CARB staff. In addition, the analysis shows that the ADF regulation will lead to significant increases in NOx emissions in the South Coast and San Joaquin Valley air basins which are already in extreme non-attainment of the federal ozone NAAQS and moderate non-attainment of the federal fine particulate NAAQS. The details of both the review and revised emissions estimates are presented in Attachment D to this declaration.

14. In addition to identifying a fundamentally flawed analysis of the increases in NOx emissions from biodiesel use under the ADF, my review indicates that other elements of the staff's air quality and environmental analyses are also fundamentally flawed. These include incorrectly selecting 2014 as the baseline year for the environmental analysis, lacking documentation and using unsupported assumptions in determination of the NOx control level for biodiesel, and unnecessarily delaying the effective date for the implementation of mitigation requirements under the ADF regulation. All of these issues, which are discussed in detail in Attachment E, cause the adverse environmental impacts of the ADF regulation to be greater than purported by CARB staff.

15. Another important issue that I have identified with the ADF regulation is that it and the related LCFS and California Diesel regulations contain inconsistent and conflicting definitions and lack provisions requiring the determination, through testing, of the biodiesel content of commercial blendstocks. As a result, there is a clear potential for biodiesel blends to actually contain as much as 5% more biodiesel by volume than will be reported to CARB under the ADF regulation. A detailed discussion of the flaws in the ADF regulation that could allow this to occur is provided in Attachment F. Actual biodiesel levels above those reported under the ADF will lead to larger unmitigated increases in NOx emissions than have been estimated by either CARB staff or me.

16. CARB staff has rejected a proposed alternative to the ADF regulation submitted by Growth Energy, claiming that it will result in the same environmental benefits but be more costly than the staff proposal. As discussed in detail in Attachment G to this declaration, this finding is based on the same fundamentally flawed emissions

analysis performed by CARB staff that is discussed above. Given that the Growth Energy alternative is designed to mitigate all potential increases in NOx emissions (when assessed in light of a proper emissions analysis) due to biodiesel use under the ADF as soon as the regulation becomes effective, it yields greater and more timely environmental benefits than the staff proposal. In addition, the Growth Energy alternative would require the same mitigation techniques as the ADF regulation, but simply expands the circumstances under which they must be applied, and has an estimated cost-effectiveness equal to that of ADF regulation. Because the Growth Energy Alternative provides greater environmental benefits as cost-effectively as the ADF regulation, it must be adopted by CARB instead of the ADF regulation.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 17th day of February, 2015 at Sacramento, California.

JAMES M. LYONS

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Attachment A

Résumé

James Michael Lyons

Education

1985, M.S., Chemical Engineering, University of California, Los Angeles

1983, B.S., Cum Laude, Chemistry, University of California, Irvine

Professional Experience

4/91 to present	Senior Engineer/Partner/Senior Partner Sierra Research

Primary responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving fuel reformulation, fuel additives, and alternative fuels, as well as accelerated vehicle/engine retirement programs, the deployment of advanced emission control systems for on- and non-road gasoline- and Diesel-powered engines, on-vehicle evaporative and refueling emission control systems, and Stage I and Stage II service station vapor recovery systems. Additional duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality regulations, product liability, and intellectual property issues.

7/89 to 4/91	Senior Air Pollution Specialist California Air Resources Board

Supervised a staff of four professionals responsible for identifying and controlling emissions of toxic air contaminants from mobile sources and determining the effects of compositional changes to gasoline and diesel fuel on emissions of regulated and unregulated pollutants. Other responsibilities included development of new test procedures and emission standards for evaporative and running loss emissions of hydrocarbons from vehicles; overseeing the development of the state plan to control toxic emissions from motor vehicles; and reducing emissions of CFCs from motor vehicles.

4/89 to 7/89 Air Pollution Research Specialist
California Air Resources Board

Responsibilities included identification of motor vehicle research needs; writing requests for proposals; preparation of technical papers and reports; as well as monitoring and overseeing research programs.

9/85 to 4/89 Associate Engineer/Engineer
California Air Resources Board

Duties included analysis of vehicle emissions data for trends and determining the effectiveness of various types of emissions control systems for both regulated and toxic emissions; determining the impact of gasoline and diesel powered vehicles on ambient levels of toxic air contaminants; participation in the development of regulations for “gray market” vehicles; and preparation of technical papers and reports.

Professional Affiliations

American Chemical Society
Society of Automotive Engineers

Selected Publications (Author or Co-Author)

“Development of Vehicle Attribute Forecasts for 2013 IEPR,” Sierra Research Report No. SR2014-01-01, prepared for the California Energy Commission, January 2014.

“Assessment of the Emission Benefits of U.S. EPA’s Proposed Tier 3 Motor Vehicle Emission and Fuel Standards,” Sierra Research Report No. SR2013-06-01, prepared for the American Petroleum Institute, June 2013.

“Development of Inventory and Speciation Inputs for Ethanol Blends,” Sierra Research Report No. SR2012-05-01, prepared for the Coordinating Research Council, Inc. (CRC), May 2012.

“Review of CARB Staff Analysis of ‘Illustrative’ Low Carbon Fuel Standard (LCFS) Compliance Scenarios,” Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

“Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory,” Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

“Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels,” Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

"Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants," Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

"Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines," Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

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"Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard," Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

"Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions," Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

"Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard," Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

"Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions," Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers' Association, and Association of International Automobile Manufacturers of Canada, August 2008.

"Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089," Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy," SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

"Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards," Sierra Research Report No. SR 2008-04-01, April 2008.

"The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles," SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

"Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin," Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

"Summary of Federal and California Subsidies for Alternative Fuels," Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

"Analysis of IRTA Report on Water-Based Automotive Products," Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

"Evaluation of Pennsylvania's Implementation of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

"Evaluation of New Jersey's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

"Evaluation of Vermont's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

"Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas," Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

"Evaluation of Connecticut's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

"Evaluation of New York's Adoption of California's Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

"Review of MOVES2004," Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

"Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies," Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

"The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future," Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

"Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions," Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

"Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers," Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

"Emission and Economic Impacts of an Electric Forklift Mandate," Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association, December 12, 2003.

"Reducing California's Energy Dependence," Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

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"Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas," Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

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"Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review", Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

"Critical Review of 'Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment', Prepared by John A Volpe Transportation Systems Center, January 2002," Sierra Research Report No. SR02-04-01, April 16, 2002.

"Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines", Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

"Review of U.S. EPA's Diesel Fuel Impact Model", Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

"Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin," Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

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“Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County,” Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

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“A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems,” Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

“Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona,” Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

“Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California,” Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

“Evaluation of CARB SIP Mobile Source Measures,” Sierra Research Report No. SR94-11-02, prepared for Western States Petroleum Association, November 1994.

“Reformulated Gasoline Study,” prepared by Turner, Mason & Company, DRI/McGraw-Hill, Inc., and Sierra Research, Inc., for the New York State Energy Research and Development Authority, Energy Authority Report No. 94-18, October 1994.

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“Cost-Effectiveness of Mobile Source Emission Controls from Accelerated Scrappage to Zero Emission Vehicles,” Paper No. 94-TP53.05, presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, OH, June 1994.

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“Evaluating the Benefits of Air Pollution Control - Method Development and Application to Refueling and Evaporative Emissions Control,” Sierra Research Report No. SR94-03-01, prepared for the American Automobile Manufacturers Association, March 1994.

“The Cost-Effectiveness of Further Regulating Mobile Source Emissions,” Sierra Research Report No. SR94-02-04, prepared for the American Automobile Manufacturers Association, February 1994.

“Searles Valley Air Quality Study (SVAQS) Final Report,” Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

“A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery,” Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

“Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities,” Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

"Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB's LEV Regulations," Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

"Size Distributions of Trace Metals in the Los Angeles Atmosphere," *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

"Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area," Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

"Development of Mechanic Qualification Requirements for a Centralized I/M Program," SAE Paper No. 911670, 1991.

"Cost-Effectiveness Analysis of CARB's Proposed Phase 2 Gasoline Regulations," Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

"Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning," in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

"The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program," SAE Paper No. 902073, 1990.

"Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin," Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles," Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"The Impact of Diesel Vehicles on Air Pollution," presented at the 12th North American Motor Vehicle Emissions Control Conference, Louisville, KY, April 1988.

"Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles," Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

"Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles," SAE Paper No. 872164, 1987.

Attachment B

Review of CARB Staff's Analysis of the GHG and Air Quality Impacts of the LCFS Regulation

In developing the proposed Low Carbon Fuel Standard (LCFS) regulation for re-adoption, CARB staff purports to have performed an analysis of the impacts that the regulation will have on emissions of both greenhouse gases and air pollutants. However, as is documented below, a review the CARB analysis demonstrates that the staff's analysis is incomplete and unsuitable for use in determining whether or not all adverse impacts have been identified and properly quantified, and all mitigation measures have been appropriately considered.

Summary of the CARB Staff Air Quality Analysis

On December 30, 2014, CARB staff released the proposed LCFS regulation language and the accompanying Initial Statement of Reasons (ISOR), Draft Environmental Analysis, and other supporting documents. Staff's analysis of the impact of the LCFS proposed for re-adoption is contained in Chapter IV of the ISOR as well as in Chapter 4.3. of the Draft Environmental Analysis.

In Table IV-2 of Chapter IV of the ISOR, CARB staff provides unsupported estimates of the reduction in GHG emissions associated with the LCFS regulation proposed for re-adoption. However, by CARB staff's own admission, the estimates presented in Table IV-2:

> *…do not include a reduction to eliminate the double counting of the Zero Emission Vehicle mandate, the federal Renewable Fuels Standard program, the Pavley standards, or the federal Corporate Average Fuel Economy program.*

Given that CARB staff has failed to estimate and report the GHG reduction benefits of the LCFS regulation proposed for re-adoption separately from other regulations that also seek to reduce GHG emissions from mobile sources, the Board and the public do not know the actual benefits expected to result from the regulation nor can alternatives to the LCFS regulation be properly evaluated by CARB staff.

Turning to the air quality analysis in Chapter IV of the ISOR, CARB staff provides a general discussion of emissions associated with transportation fuel production at California refineries, as well as ethanol, biodiesel, renewable diesel, and potential cellulosic ethanol facilities. Emission factors in, terms of pollutant emissions per year per million gallons of fuel produced, are provided for some facilities. CARB staff also provides an undocumented analysis of NOx and $PM_{2.5}$ emissions associated with "*...the movement of fuel and feedstock in heavy-duty diesel trucks and railcars*" with and without the LCFS and ADF regulations in place. No other assessment of the air quality impacts associated with the LCFS is provided in the LCFS ISOR.

As noted above, the draft Environmental Analysis (EA) for the LCFS and ADF, which is Appendix D to both the LCFS and ADF ISORs, also addresses air quality in Chapter 4.3. Here, short term air quality impacts related to the construction of projects of various types related to the production and distribution of lower carbon intensity fuels under the LCFS are presented. There is, however, no analysis that indicates where these projects will be located within California, nor any quantitative assessment of the emission and environmental impacts beyond the following:

> *Based on typical emission rates and other parameters for abovementioned equipment and activities, construction activities could result in hundreds of pounds of daily NO_x and PM emissions, which may exceed general mass emissions limits of a local or regional air quality management district depending on the location of generation. Thus, implementation of new regulations and/or incentives could generate levels that conflict with applicable air quality plans, exceed or contribute substantially to an existing or projected exceedance of State or national ambient air quality standards, or expose sensitive receptors to substantial pollutant concentrations.*

There is also a general discussion of potential approaches to mitigation, which CARB staff concludes are outside of the agency's authority to adopt. Ultimately, the draft EA concludes that the "short-term construction-related air quality impacts…associated with the proposed LCFS and ADF regulations would be potentially significant and unavoidable."

The draft EA also purports to assess the long-term impacts of the LCFS and ADF regulations, but addresses and attempts to quantify only potential increases in NOx emissions due to the use of biodiesel fuels, and concludes with CARB staff ultimately claiming that the long term impacts of the LCFS and ADF on air quality will be "beneficial."

Review of the CARB Staff Air Quality Analysis

As summarized above, the air quality related analyses performed by CARB staff regarding the proposed LCFS regulation are both limited and cursory. In order to demonstrate that this is in fact the case, one has to look no further than the air quality analysis CARB staff performed in 2009 to support the original LCFS rulemaking.[1]

[1] California Air Resources Board, Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume I: Staff Report: Initial Statement of Reasons, March 5, 2009 and Volume II: Appendices, March 5, 2009. See in particular, Chapter VII of the ISOR and Appendix F.

The first point of note is that in the 2009 ISOR, CARB staff presents quantification of the GHG reductions expected from the LCFS occurring both in California and worldwide in Tables VII-1 and VII-2. While, those estimates have no relevance to the current rulemaking given the differences in the two regulations, fundamental changes in CARB's expectations with respect to how fuel producers will comply with a LCFS regulations, as well as the evolution of methodologies for estimating GHG emissions, provide clear evidence that the GHG emission benefits of the proposed LCFS can and should be explicitly quantified without any "double counting" of the benefits due to other regulatory programs. It should also be noted that in the 2009 ISOR, CARB staff also breaks down the GHG emission benefits expected from specific substitutes for gasoline and diesel fuel.

Turning to the air quality analysis itself, the lack of documentation provided precludes any detailed review of the accuracy of the assumptions and methodologies underlying the analysis or any effort to attempt to reproduce the staff's results. Given this lack of documentation, additional information was requested from CARB. As part of this request, Sierra Research pointed out that pursuant to the requirements of AB 1085, the agency had provided far more detailed information for other recent major rulemakings, including the Advanced Clean Cars program, than it released regarding the LCFS and ADF proposals. Unfortunately, CARB staff choose not to provide any additional information related to the analyses underlying the proposed LCFS and ADF regulations.

Another striking contrast which highlights the superficiality of the air quality analysis performed for the re-adoption of the LCFS can be seen in the treatment of potential emission impacts associated with the development of biofuel production facilities in California. These impacts are particularly important because the form of the LCFS regulation provides incentives to build biofuel production facilities in areas of California that violate federal National Ambient Air Quality standards, rather than in other states that are in compliance with those standards. The incentive for locating biofuel plants in California is to avoid GHG emissions from fuel and/or feed stock transportation which result in higher carbon intensity values.

As noted above, the air quality analysis for the re-adoption of the LCFS presented in section IV of the ISOR provides only estimates for existing California biofuel production facilities and the potential emissions of NO_x, PM_{10}, and volatile organic compounds (VOCs) associated with a hypothetical "northern California" cellulosic ethanol plant. In contrast, in the 2009 ISOR, staff provides a quantitative estimate of the overall number and types of new biofuel production facilities expected to be built in California (Table VII-6 of the 2009 ISOR) as well as a distribution of the number and type of plants expected to be built in eight of the state's air basins and a map showing expected locations. The increases in emissions of not only NO_x, PM_{10}, and VOC, but also carbon monoxide (CO) and $PM_{2.5}$ associated with these biodiesel production facilities were quantified by CARB staff (Table V11-10 of the 2009 ISOR). Again, although the data presented in the 2009 LCFS ISOR are irrelevant with respect to the current re-adoption of the LCFS regulation, the same level of detail and scope of the analysis performed by CARB staff in 2009 should have at a minimum been applied to the current LCFS air quality analysis.

Another issue noted with the air quality analysis performed for the re-adoption of the LCFS is related to emission impacts associated with "fuel and feedstock transportation and distribution."

The total impact of the LCFS and ADF on NOx and $PM_{2.5}$ emissions from these activities, which constitute a long term operational impact on air quality, are quantified in Table IV-16 of the ISOR. However, the documentation provided describing how the staff's analysis was performed is insufficient to allow one to either review or reproduce it. Further, these emissions are not addressed in the appropriate section of the draft EA. Given that staff estimates that the LCFS/ADF will increase these emissions, they should be identified and assessed as part of the draft EA, particularly given that staff has concluded that the LCFS/ADF impacts on long term air quality are beneficial without considering fuel and feedstock transportation and distribution emissions. The current analysis of these emissions also falls far short of the level of detail shown in the analysis of the same issue performed by CARB staff in the 2009 ISOR, as can be seen in Table VII-11 where impacts on VOC, CO, PM_{10}, and oxides of sulfur (SO_x) were reported by low CI fuel type.

Again, as noted above, the only issue addressed with respect to long term LCFS/ADF air quality impacts in the draft EA are potential NOx emission increases due to the use of biodiesel blends. As discussed in detail elsewhere,[2] the analysis upon which the draft EA and its conclusions are based is fundamentally flawed. However, the air quality analysis in the draft EA is also incomplete in that it fails to address long term changes in motor vehicle emissions beyond those associated with biodiesel and renewable diesel. That such impacts should have been addressed for the current rulemaking can be seen from the CARB staff air quality analysis included in the 2009 ISOR and presentation, which included detailed estimates of motor vehicle impacts on VOC, CO, NOx, SOx, PM_{10}, and $PM_{2.5}$ (rather than just NOx and $PM_{2.5}$) as a function of vehicle and fuel type in Table VII-12.

In addition to the above, two other important issues are: 1) CARB staff's failure to even attempt to quantify construction emissions associated with biofuel production facilities in California after finding them to be potentially significant and unavoidable; and 2) to identify and quantify potential emission increases associated with an increase in the number of tanker visits to California ports as the result of the ADF and LCFS regulations. With respect to the former, a California specific tool, CalEEmod,[3] is readily available that could have been used by CARB staff in estimating construction impacts form biofuel plants located in California.

With respect to the latter, it should be noted that although CARB staff concluded in the 2009 LCFS air quality analysis that there would be "little to no change to emissions at ports," that analysis predates the current proposal[4] regarding the assignment of CI to crude oil which are likely to encourage crude oil shuffling; as well as CARB staff assumptions regarding increases in assumed volumes of renewable diesel fuel potentially coming to California from production facilities in Asia, and the potential for direct importation of cane ethanol into California from Brazil. These factors will undoubtedly result in increased tanker operations in California waters the emission impacts of which can be estimated using the Emissions Estimation Methodology for Ocean-Going Vessels available on CARB's emission inventory website. According to this source, 1,919 visits by crude oil and petroleum product tankers are forecast for 2015 with roughly 50% percent of those trips involving southern California ports that are part of the South

[2] Declaration of James M. Lyons filed as comments to the ADF regulation.
[3] California Emissions Estimator Model, Users Guide, Version 2013.2, July 2013.
[4] See proposed section 95489, Title 17 CCR in LCFS ISOR Appendix A.

Coast air basin. The emissions estimated by CARB to be associated with one tanker visit to California are presented in Table 1. As shown, the tanker emissions associated with a single new visit far exceed the NOx, $PM_{2.5}$ and SOx significance thresholds. Given that multiple new tanker visits are likely to result from the LCFS and ADF regulations, these values demonstrate that CARB staff has failed to identify a potentially significant source that will created adverse air quality impacts in its draft EA.

Table 1
Comparison of Tanker Emissions During A Single Visit to California with South Coast Air Quality Management District Air Quality Significance Thresholds

Pollutant	Significance Threshold (lbs/day)	Tanker Emissions (lbs)
NOx	55	7,700
VOC	55	283
PM_{10}	150	290
$PM_{2.5}$	55	283
SOx	150	1,780
CO	550	629

Attachment C

The Growth Energy Alternative to the Proposed LCFS Regulation is the Least-Burdensome Approach that Best Achieves the Project Objectives at the Least Cost That Must be Adopted

As part of the rulemaking process leading to CARB staff's proposed re-adoption of the LCFS regulation, staff was required to solicit and consider alternatives to the proposed regulation. Growth Energy submitted such an alternative. While CARB staff acknowledged that the Growth Energy alternative could provide equivalent reductions in GHG emissions, the agency rejected it from further consideration or analysis by stating only that it was insufficient to transition California to alternative, lower carbon intensity fuels. As discussed below, CARB staff's premise for rejecting the Growth Energy alternative is incorrect. Further, given that the Growth Energy Alternative achieves the same environmental benefits through reductions in GHG emissions as the LCFS regulation, likely at the same or lower cost, it should have been analyzed by CARB staff, in which case it would have to be adopted as the least-burdensome approach the best achieves the project objectives at the least cost.

Background

On May 23, 2014, CARB published a "Solicitation of Alternatives for Analysis in the LCFS Standardized Regulatory Impact Assessment" which is attached. On June 5, CARB published a response to a request from Growth Energy extending the deadline for the submission of alternatives from June 5, 2014 to June 23, 2014. On June 23, 2014, Growth Energy submitted an alternative regulatory proposal for the LCFS regulation (which is attached) to CARB in response to the agency's solicitation. On December 30, 2014, CARB staff published both the ISOR for the LCFS regulation as well as a document entitled "Summary of DOF Comments to the Combined LCFS/ADF SRIA and ARB Responses," which is Appendix E to the LCFS ISOR. Appendix E discusses the Growth Energy LCFS alternative and CARB's reason for its rejection.

The staff's assessment of the Growth Energy (GE) Alternative published in Appendix E of the LCFS ISOR is as follows (emphasis added):

> *The proposed alternative assumes that the exclusive goal of the LCFS proposal is to achieve GHG emissions reductions without regard to source. If that were the case, this would be a viable alternative to the LCFS and would be assessed in this analysis. It is likely true that the estimated GHG emissions reductions appearing in the 2009 LCFS Initial Statement of Reasons (California Air Resources Board, 2009) could be achieved by the AB 32 Cap-and-Trade Program, along with the other programs cited by Sierra Research and Growth Energy. The LCFS proposal, however, was designed to address the carbon intensity of transportation*

fuels. Transportation in California was powered almost completely by petroleum fuels in 2010. Those fuels were extracted, refined, and distributed through an extensive and mature infrastructure. Transitioning California to alternative, lower-carbon fuels requires a very focused and sustained regulatory program tailored to that goal. The other regulatory schemes the alternative would rely on are comparatively "blunt instruments" less likely to yield the innovations fostered by the LCFS proposal. In the absence of such a program, post-2020 emissions reductions would have to come from a transportation sector that would, in all likelihood, have emerged from the 2010-2020 decade relatively unchanged.

In the absence of an LCFS designed to begin the process of transitioning the California transportation sector to lower-carbon fuels starting in 2010, post-2020 reductions would be difficult and costly to achieve. This is why the primary goals of the LCFS are to reduce the carbon intensity of California fuels, and to diversify the fuel pool. A transportation sector that achieves these goals by 2020 will be much better positioned to achieve significant GHG emissions reductions post 2020.

ARB is required to analyze only those alternatives that are reasonable and that meet the goals of the program as required by statute. An initial assessment of the program indicates the goals of the LCFS proposal can be achieved by keeping the program "…separate of the AB 32 Cap-and-Trade system initially (at least first 10 years) in order to stimulate innovation and investment in low-GWI [global warming intensity] fuel (or transportation) technologies."[16] Due to the strong justifications that the Cap-and-Trade program alone generates neither the CI reductions nor fuel in the transportation sector, this alternative will not be assessed in this document.

Reference 16 in the above citation is given as:

A Low-Carbon Fuel Standard for California, Part 2: Policy Analysis – FINAL REPORT, University of California Project Managers: Alexander E. Farrell, UC Berkeley; Daniel Sperling, UC Davis. Accessed: 7-15-2015 http://www.energy.ca.gov/low_carbon_fuel_standard/

Discussion

Given that there is no analysis or other support provided by CARB staff for the assertions it makes in rejecting the Growth Energy alternative other than the one reference, which dates to 2007—before either the original LCFS or Cap-and-Trade regulation were adopted was reviewed. The discussion of interactions between a LCFS program with AB32 regulations from the reference is provided below. As can be determined by the reader, the discussion was written before the AB32 regulations were adopted, and the basic concern expressed is that the lower cost of achieving the same GHG reductions from a broader program will be lower than the cost of doing the same from the LCFS program. Further, the concern expressed regarding lifecycle emission under the LCFS was explicitly addressed in the Growth Energy alternative.

5.2 Interactions with AB32 regulations

RECOMMENDATION 16: The design of both the LCFS and AB32 polices must be coordinated and it is not possible to specify one without the other. However, it is clear that if the AB32 program includes a hard cap, the intensity-based LCFS must be separate or the cap will be meaningless. Including the transport sector in both the AB32 regulatory program and LCFS will provide complementary incentives and is feasible. CARB will soon be developing regulations under AB32 to control GHG emissions broadly across the economy, most likely through a cap-and-trade system plus a set of regulatory policies. Thus, emissions from electricity generation, oil production, refining, and biofuel production are likely to be regulated directly under AB32. These energy production emissions are "upstream" in a fuel's life cycle (while emissions from a vehicle are "downstream"). The recent Market Advisory Committee report recommends including all CO2 emissions from transportation, including tailpipe emissions.

The LCFS regulates consumption emissions—the full life cycle emissions associated with products consumed in California, while it is expected that sector-specific emission caps will be imposed by AB 32 on production emissions—the emissions that are directly emitted within the borders of the state. The different types of boundaries used by these regulations causes certain upstream emissions to be double regulated under the LCFS and AB32. However, the potential for double regulation only applies to fuel production processes in the state of California or other jurisdictions where legislation similar to AB 32 also applies. We agree with the Market Advisory Committee that the LCFS and AB32 regulations will provide complementary incentives and that transportation emissions of GHGs should be included in the AB32 program.

There is no inherent conflict between the LCFS and AB32 caps; both are aimed at reducing GHG emissions and stimulating innovation in low-carbon technologies and processes. However, there are some differences. Most importantly, the LCFS is designed to stimulate technological innovation in the transportation sector specifically, while the broader AB32 program will stimulate technological innovation more broadly. The concerns associated with market failures and other barriers to technological change in the transportation sector (discussed in Section 1.3 of Part 1 and Section 2.3 of Part 2) are the motivation for adopting the sector-specific LCFS. These concerns suggest separating the LCFS from the AB32 emission caps.

The second key difference is that as a product standard using a lifecycle approach, the LCFS includes emissions that occur outside of the state such as *those associated with biofuel feedstock production and the production of imported crude oil. These emissions will not be included in the AB32 regulations.*

The third difference is in expected costs. In the absence of transaction costs and other market imperfections, economic theory suggests that a broader cap-and-trade program will be less costly than a narrower one. By allowing more sectors and more firms to participate in a market for emission reductions, one reduces the cost to achieve a given level of emission reductions -- suggesting that the LCFS be linked to the broader AB 32 regulatory system. In addition, commercially available low-carbon options exist in the electricity and other sectors, but not in transportation fuels (see Part 1 of this study, Section 1.3).

The specific regulations and market mechanisms used to implement AB32 are not yet determined, so it is not possible at this time to specify how the LCFS should interact with them. The ARB should carefully consider the differences in incentives and constraints that the combination of rules will create.

Returning to the issue of diversification of the transportation fuel sector, CARB concerns are directly refuted by Growth Energy's submission. As noted on pages 9 and 10, ethanol will be added to California gasoline, and renewable diesel and biodiesel will be blended into California diesel fuel as the result of the federal RFS program. The range of fuels and feedstocks from which they are produced under the RFS will be diverse. For example, the following fuel/feedstock pathways, among others, are currently recognized by U.S. EPA under the RFS:[1,2,3,4,5]

- Ethanol from
  - Corn
  - Sugar cane
  - Grain sorghum
  - Celluosic materials

- Biodiesel from
  - Camelina oil
  - Soy bean oil
  - Waste oils, fats and greases
  - Corn oil
  - Canola/rapseed oil

- Renewable diesel from
  - Waste oils, fats and greases

[1] EPA-420-F-13-014
[2] EPA-420-F-14-045
[3] EPA-420-F-12-078
[4] EPA-420-F-11-043
[5] EPA-420-F-10-007

- Renewable gasoline from
    - Crop residue and municipal solid waste

- Renewable natural gas from
    - Landfills
    - Digesters

As can be seen from Appendix B to the LCFS ISOR, these are many of the fuels that CARB staff also expects to be used in California under the LCFS. Similarly, electricity and hydrogen will be used as transportation fuels in California given the states regulatory mandates for the production of vehicles that operate on these fuels under the Advanced Clean Cars program. Further, in later years these fuels are expected to be required in heavy-duty vehicles as CARB adopts regulations under its proposed Sustainable Freight Transport Initiative, the purpose of which is stated by CARB staff as follows:

> *The purpose of the Strategy is to identify and prioritize actions to move California towards a sustainable freight transport system that is characterized by improved efficiency, zero or near-zero emissions, and increased competitiveness of the logistics system.*

It should also be noted that fuel providers in California will still be incentivized to provide these fuels in California under the Growth Energy alternative in order to reduce the number of GHG credits they will be required to retire under cap-and-trade program.

Finally, on pages 15 and 16, Growth Energy's proposal for addressing the loss of upstream emission benefits from the LCFS regulation is explicitly discussed.

Given that the Growth Energy alternative:

1. Provides, as determined by CARB staff, the same GHG reductions as the LCFS regulation; and

2. Is expected to result in lower costs of compliance than the LCFS.

CARB must adopt the Growth Energy alternative as it better achieves the stated project objectives in an equally cost-effective manner.

Attachment D

Review of CARB Staff Estimates of NOx Emission Increases Associated with the Use of Biodiesel in California Under the Proposed ADF Regulation

In developing the proposed Alternative Diesel Fuel (ADF) regulation, CARB staff has performed a statewide analysis of the increase in NOx emissions that is currently occurring in California due to the use of biodiesel, as well as the increases in NOx emissions that can be expected in the future due to the continued use of biodiesel in California under the proposed ADF regulation. As documented below, a review of the CARB staff analysis performed by Sierra Research demonstrates that the staff's analysis is fatally flawed and cannot be relied upon. Given this, Sierra Research has performed an analysis, also documented below, that demonstrates there will be substantial increases in NOx emissions if the ADF regulation is implemented as proposed. The significance in the NOx emissions increase associated with the use of biodiesel under the proposed ADF is clear given the dramatic reductions which CARB, the South Coast Air Quality Management District, and the San Joaquin Air Pollution Control District are seeking given their "extreme" non-compliance status with respect to the federal National Ambient Air Quality Standard for ozone.[1] This significance is also reinforced by a comparison of the estimated increase in NOx emissions from biodiesel under the proposed ADF regulation with the benefits of proposed and adopted NOx control measures intended for implementation on a statewide basis as well as in the South Coast and San Joaquin Valley air basins, respectively.

Review of the CARB Staff Analysis

On December 30, 2014, CARB staff released the proposed ADF regulation language and the accompanying Initial Statement of Reasons (ISOR), technical and economic support information, and draft environmental analysis. Staff's analysis of the impact of the proposed ADF regulation on NOx emissions and supporting information and assumptions are contained in Chapters 6 and 7 of the ISOR, as well as Appendix B entitled "Technical Supporting Information."

The first issue that was identified with the staff's emissions analysis is that the information and data supplied by CARB staff are insufficient to determine exactly how the analysis was performed. Specifically, CARB staff provides no source for the values in Table B-1 labeled "Emission Inventory (Diesel TPD)," which are key to the analysis. As illustrated below, a clear understanding of what diesel sources (e.g., on-road heavy-duty, non-road, marine, locomotives, etc.) are included in the "inventory" is critical to assessing the accuracy of the staff's analysis.

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[1] It should be noted that the CARB statewide analysis fails to provide any estimate of the impacts of increased NOx emissions from the ADF regulation in these air basins, where the agency has stated that massive reductions in NOx emissions are required to achieve compliance with federal air quality standards.

Given the lack of documentation regarding the source of the diesel emission inventory values, additional information regarding this analysis as well as other analyses associated with the ADF and Low Carbon Fuel Standard (LCFS) rulemakings was requested. As part of this request, Sierra Research pointed out that pursuant to the requirements of AB 1085, the agency had provided far more detailed information for other recent major rulemakings, including the Advanced Clean Cars program, than it released regarding the LCFS and ADF proposals. Unfortunately, CARB staff choose not to provide any additional information related to the analyses underlying the proposed LCFS and ADF regulations.[2]

Despite the lack of all the information necessary to fully review the CARB staff analysis, it was possible to discern some key assumptions and the general methodology that was applied. The following key assumptions were identified:

1. Actual biodiesel use and the total demand for diesel fuel and substitutes in California will exactly match that forecast by CARB staff in the "illustrative compliance scenarios" developed as part the LCFS rulemaking;[3]

2. Actual renewable diesel use in California will exactly match that forecast by CARB staff in the "illustrative compliance scenarios" developed as part the LCFS rulemaking;[2]

3. Forty percent of renewable diesel delivered to California will be used directly by refiners to comply with the requirements of CARB's existing diesel fuel regulations[4] while the remaining 60% will be blended into fuel that complies with the diesel fuel regulations downstream of refineries;

4. The use of biodiesel up to the B20 level in New Technology Diesel Engines[5] (NTDEs, which employ exhaust aftertreatment systems to reduce NOx emissions) will not result in any increase in NOx emissions;

5. The use of biodiesel in heavy-duty diesel engines other than NTDEs—which are referred to by CARB staff as "legacy vehicles"—will increase NOx linearly with increasing biodiesel blend content, up to a 20% increase for B100;

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[2] See attached emails from Jim Lyons of Sierra to Lex Mitchel and other CARB staff from January 2015.
[3] These are presented in Appendix B to the LCFS ISOR.
[4] Sections 2281 to 2284, Title 13, California Code of Regulations.
[5] Proposed section 2293.3 Title 13 CCR (see Appendix A to the LCFS ISOR) defines a New Technology Diesel Engines as:

a diesel engine that meets at least one of the following criteria:

(A) Meets 2010 ARB emission standards for on-road heavy duty diesel engines under section 1956.8.
(B) Meets Tier 4 emission standards for non-road compression ignition engines under sections 2421, 2423, 2424, 2425, 2425.1, 2426, and 2427.
(C) Is equipped with or employs a Diesel Emissions Control Strategy (DECS), verified by ARB pursuant to section 2700 et seq., which uses selective catalytic reduction to control Oxides of Nitrogen (NOx).

6. The blending of renewable diesel downstream of refineries will reduce NOx emissions from legacy vehicles, with each 2.75 gallons of renewable diesel blended offsetting the emissions increase associated with each gallon of biodiesel used; and

7. During the period from 2018 to 2020, 30 million gallons of biodiesel will be blended to the B20 level for use in legacy vehicles each year, and will therefore be subject to the mitigation requirements of the proposed ADF regulation and will not cause an increase in NOx emissions. Furthermore, this volume will increase to 35 million gallons per year from 2021 to 2023.

Based on the above assumptions, CARB staff followed the methodology steps outlined below for estimating biodiesel impacts.

1. The fraction of legacy vehicles in a given year is determined by subtracting the percentage of vehicle miles traveled by on-road heavy-duty vehicles with NTDEs from 100%.

2. The fraction of legacy vehicles from Step 1 is multiplied by the total volume of biodiesel assumed to be consumed in a given year to yield the number of gallons of biodiesel used in legacy vehicles in that year.

3. For years 2018 and later, the amount of biodiesel assumed to be sold as emissions-mitigated B20 in a given year is subtracted from the total volume of biodiesel used in legacy vehicles in that year.

4. The total volume of renewable diesel assumed to be sold in a given year is multiplied by the percentage of legacy vehicles in that year and then multiplied by 0.6 to account for renewable diesel used in refineries to yield the amount of renewable diesel creating reductions in NOx emissions from legacy vehicles in that year.

5. The amount of renewable diesel used in legacy vehicles is then divided by 2.75 to determine the number of gallons of biodiesel for which NOx emissions have been offset for that year.

6. The number of gallons of biodiesel for which NOx emissions have been offset, as determined in Step 5, is then subtracted from the amount of biodiesel used in legacy vehicles, as determined in Step 3, to yield the total number of gallons of biodiesel used in legacy vehicles that cause increased NOx emissions for that given year.

7. The biodiesel volume from Step 6 is multiplied by the assumed NOx increase of 20% for B100 and then divided by the total volume of diesel fuel forecast to be used in that year to get the percentage increase in diesel emissions for that year.

8. The value from Step 7 is multiplied by the assumed Diesel Emissions inventory for that year to yield the final estimate of increased NOx emissions due to biodiesel in units of tons per day for the entire state of California.

Using the above methodology, CARB staff estimates that use of biodiesel in California led to a 1.36 ton per day increase in NOx emissions in 2014, and that the proposed ADF regulation will reduce the magnitude of that increase through 2023 down to 0.01 ton per day.[6]

The review of the staff's emission analysis identified two major issues in addition to the lack of documentation regarding how the diesel "Emission Inventory" values used by staff were developed:

1. Assuming that biodiesel use in NTDEs at levels up to B20 will not increase NOx emissions; and

2. Assuming that biodiesel NOx emissions are offset by the use of renewable diesel fuel.

Beginning with NTDEs, it has been demonstrated[7] that the available data indicate not only that NOx emissions from NTDEs will increase with the use of biodiesel in proportion to the amount of biodiesel present in the blend, but also that the magnitude of the increase on a percentage basis will be much greater than that observed for "legacy vehicles." At the B20 level where CARB staff assumed that there will be no NOx increase, the best current estimate is that NTDE NOx emissions will be increased by between 18% and 22%. CARB staff's failure to account for increased NOx emissions from NTDEs renders the staff's emission analysis meaningless in terms of assessing the adverse environmental impacts of the proposed ADF regulation. Another problem with CARB staff's treatment of NTDEs is that they have incorrectly assumed that the penetration of NTDEs into the on-road fleet is equal to that in the non-road fleet. NTDE penetration rates into the non-road fleet will be delayed due to the later effective date of the Tier 4 Final standards, relative to the 2010 on-road standards, and by the fact that while newer trucks dominate on-road heavy-duty vehicle operation, that effect does not occur in the non-road vehicle population.

Similarly, there are fundamental flaws with CARB staff's assumption that the use of renewable diesel will offset increased NOx emissions due to the use of biodiesel. First, it must be noted that there is nothing in either the proposed ADF regulation or the proposed LCFS regulation that mandates the use of any volume of biodiesel in California, much less the use of the exact ratio of renewable diesel to biodiesel assumed by CARB staff in its emissions analysis. Second, based on a review of the ADF and LCFS ISORs and supporting materials, there is no apparent basis for the staff's assumption that 40% of renewable diesel used in California will be used by refiners to aid in compliance with CARB's existing diesel fuel regulations, and that 60% will be blended downstream of refineries. To the extent that fuel producers choose to blend renewable diesel in California, one would expect them to do so by purchasing renewable diesel for use at their

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[6] Table B-1, Appendix B of the ADF ISOR.
[7] "NOx Emission Impacts of Biodiesel Blends," Rincon Ranch Consulting, February 17, 2015.

refineries where they can benefit from the other desirable properties of this fuel beyond its low carbon intensity (CI) value (e.g., high cetane number and fungibility with diesel fuel at all blend levels), rather than by purchasing LCFS credits generated by downstream blenders of renewable diesel fuel.

To illustrate the magnitude of the significance of CARB's flawed assumptions regarding NTDEs and renewable diesel, if one simply and extremely conservatively assumes that NTDE NOx increases will be the same on a percentage basis as legacy vehicles and eliminates the NOx offsets assumed from renewable diesel, the NOx increases expected from biodiesel increase from 1.35 tons per day statewide in 2014 to approximately 3.44 tons per day—a factor of about 2.65. For 2023, estimated NOx emission increases due to biodiesel rise to about 0.87 tons per day, or about 100 times more than the 0.01 tons per day CARB staff estimated. However, as documented below, a more rigorous analysis indicates that far greater increases in NOx emissions are likely.

Detailed Analysis of Increases in NOx Emissions from Biodiesel Use

Given the flawed assumptions and undocumented sources of data associated with CARB staff's analysis of the emission impacts associated with biodiesel under the proposed ADF, Sierra Research undertook a detailed analysis of the same issue. The first step in this analysis was identifying the most current methods and tools for estimating NOx emissions from on- and non-road diesel engines operating in California for which biodiesel use is expected to increase NOx emissions.

On-Road Heavy-Duty Diesel Vehicles – On December 30, 2014, CARB officially released the final version of the EMFAC2014 model for estimating on-road emissions in California, which has replaced the now obsolete EMFAC2011 model that CARB staff relied upon for certain elements of its emission analysis. In releasing EMFAC2014, CARB staff noted a number of changes intended to improve the accuracy of the model relative to EMFAC2011. First, EMFAC2014 accounts for CARB's adoption of recent mobile source rules and regulations that lower future NOx emission estimates, including the Advanced Clean Cars program and the 2014 Amendments to the Truck and Bus Regulation. In addition, EMFAC2014 now estimates off-cycle emissions of SCR-equipped vehicles (i.e., NTDEs) by reflecting higher NOx emissions during low speed operation and cold starts.[8]

Given the above, Sierra selected EMFAC2014 for estimating NTDE emissions directly in this assessment. It was used to generate annual average NOx emissions, in tons per day, for the South Coast and San Joaquin Valley Air Basins, and the entire state for the years 2015, 2020, and 2023. Emission estimates were obtained for light-heavy-duty, medium-heavy-duty, and heavy-heavy-duty trucks, as well as school, urban, and transit buses. Output by "model year" was used to differentiate NOx emissions of legacy vehicles from those of NTDEs, which were defined as 2010 and later model-year vehicles consistent with the definition in proposed section 2293.2 Title 13, CCR (see Appendix A to the LCFS ISOR).

[8] Email from ARB EMFAC2014 Team, November 26, 2014.

Off-Road Diesel Equipment and Engines – The process of estimating emissions from off-road equipment and engines in California is much less straightforward than for on-road vehicles, as the most recent CARB models have been separated by equipment type and updated at various points in time as part of the rulemaking process associated with the development of regulations for different source categories.

In addition to having been developed and last updated at different points in time, some of the methodologies do not output data with sufficient detail (e.g., emissions by engine model year) to differentiate between "legacy vehicles" and NTDEs, which, in the case of off-road sources, are defined by CARB staff in proposed section 2293.2 Title 13 CCR as being compliant with Tier 4 final emission standards for non-road compression ignition (i.e., diesel) engines under sections 2421, 2423, 2424, 2425, 2425.1, 2426, and 2427 Title 13 CCR.[9] The effective dates of these standards vary as a function of engine power rating, as shown in Table 1. It should be noted that compliance with the Tier 4 Final standards by engines below 50 horsepower in general does not require the use of the SCR technology[10] that CARB has used to define "NTDEs." Therefore, all engines in this category were assumed to respond to biodiesel in the same way as legacy vehicles, despite the fact that they meet Tier 4 final standards and are technically classified as NTDEs by CARB under the ADF regulation. As discussed below, this again reduced the magnitude of the biodiesel NOx impact.

Table 1
Effective Dates of Tier 4 Final Standards

Horsepower Range	Model Year
50-75	2013
76-175	2015
176-750	2014
Over 751	2015

Table 2 summarizes current state of CARB inventory models and methodologies for off-road diesel emission sources by equipment/engine sector[11] and indicates which outputs have sufficient detail to differentiate between emissions from legacy vehicles and NTDEs. As shown, only the general off-road equipment (construction, industrial, ground support, and oil drilling equipment), cargo handling equipment, and agricultural equipment sectors could be included in the Sierra analyses for the South Coast and San Joaquin Valley Air Basins. For the statewide inventory, it was possible to include transportation refrigeration units (TRUs) as well. Given that all diesel emission categories could not be included in the Sierra analysis, it should be noted that the results of the analysis presented below are conservative in that they do not account for the full magnitude of the increase in NOx emissions related to biodiesel use in California.

[9] See ISOR Appendix A.
[10] See *http://www.arb.ca.gov/diesel/tru/tru.htm#mozTocId341892.*
[11] All models can be downloaded at *http://www.arb.ca.gov/msei/categories.htm* .

The CARB off-road emissions inventory tools were configured to include the impacts of the most recent regulatory actions in each sector, and were executed to provide estimates of annual average day NOx emissions for both legacy and NTDE vehicles for calendar years 2015, 2020, and 2023 occurring in the South Coast and San Joaquin Valley Air Basins, as well as the entire state.

Key Assumptions: The Sierra analysis of the emission impacts of biodiesel use in California relies on the following two key assumptions:

1. B5 will be in use on a statewide basis in 2015, 2020, and 2023;

2. At the B5 level, NOx emissions from legacy vehicles will be increased by 1%, and by 5% from NTDEs.

Table 2
Summary of Current California Off-Road Diesel Emission Inventory Methodologies

Category	CARB Model/Database Tool	Capable of Differentiating Legacy Vehicle and NDTE Emissions
In-Use Off-Road Equipment	2011 Inventory Model	Yes
Cargo Handling Equipment	2011 Inventory Model	Yes
Transportation Refrigeration Units	2011 TRU Emissions Inventory	Yes – but not capable of estimating emissions by air basin
Agricultural Equipment	OFFROAD2007	Yes
Stationary Engines	2010 StaComm Inventory Model	No
Locomotives	NA	No
Commercial Harborcraft	2011 CHC/CA Crew and Supply Vessel/CA Barge and Dredge Inventory Databases	No
Ocean-Going Vessels	2011 Marine Emissions Model	No

The assumption regarding B5 was based on the fact that it represents the highest blend allowed under the ADF without mitigation, at least during the summer months. That this assumption is reasonable can be seen by comparing CARB's current and previous assumptions of biodiesel use: in the current LCFS compliance scenario,[3] the staff assumes a range from about B3 in 2015 to about B4 in 2020; in 2009,[12] the staff assumed approximately B1 in 2015 and B5 in 2020; and

[12] CARB, Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume II, Appendices, March 5, 2009.

in 2011,[13] approximately B10 in 2015 and B20 in 2020 were assumed. Furthermore, the Sierra results can be scaled to reflect lower or higher non-mitigated biodiesel levels by multiplying them by the ratio of the assumed biodiesel level to B5.

The assumptions of a 1% and 5% increase at B5 for legacy vehicles and NTDEs, respectively, are based on the analysis of Rincon Ranch Consulting,[7] where 5% represents the mid-point of the range of estimates.

Diesel Emission Inventory and Biodiesel Impacts

The results of the Sierra analysis for the statewide diesel inventory for 2015, 2020, and 2023 are presented in Table 3 along with the undocumented values published by CARB staff.[6] As shown, the Sierra values are lower than those used by CARB staff. This is expected to some degree given that the Sierra analysis does not include, as explained above, some diesel source categories; however, the difference cannot be reconciled given the lack of information made available by CARB staff regarding its analysis.

Table 3
Statewide Diesel Emissions tons/day

	2015	2020	2023
Sierra Analysis	621	436	277
CARB Table B-1, Appendix B ADF ISOR	863	634	496

Table 4 compares the results of Sierra's analysis with the results of the CARB staff's analysis. As shown, the differences are large and are due primarily to two factors: 1) the staff's assumption regarding biodiesel impacts on NTDE NOx emissions, which is contradicted by the available data; and 2) the differences in the assumed levels of biodiesel use. The impact of the latter difference can also be seen in the results presented in Table 4, where results from the Sierra analysis scaled to reflect the lower biodiesel use rates assumed by CARB staff are presented. Again, even with this adjustment, the results of the Sierra analysis indicate much greater NOx impacts under the proposed ADF. Finally, it should be recalled that because of limitations with CARB's emission inventory methods for off-road sources, not all sources of diesel emissions that could be impacted by biodiesel use under the ADF have been accounted for, and the actual impacts will be greater than those shown in Table 4.

[13] CARB, Low Carbon Fuel Standard 2011 Program Review Report, December 8, 2011.

Table 4 Statewide Increase in NOx Emissions Due to Biodiesel tons/day			
	2015	2020	2023
Sierra Analysis – B5	9.18	9.73	8.75
Sierra Analysis at CARB Assumed Biodiesel Levels from Table B-1	4.70	7.15	6.15
CARB Table B-1, Appendix B ADF ISOR	1.29	0.39	0.01

The results of the Sierra analysis are shown graphically in Figures 1a through c for the entire state as well as the South Coast and San Joaquin air basins, respectively. These figures also show the relative contributions of legacy vehicles and NTDEs to the total estimated for each area and year. As shown, the contributions of NTDEs to increased NOx emissions are substantial in 2015, and dominate the impacts in 2020 and 2023. Further data supporting these results are provided in Tables 6 through 8 at the end of this attachment.

Figure 1a
Results of Sierra Analysis of Statewide NOx Increases Due to Biodiesel Use under the Proposed ADF Regulation

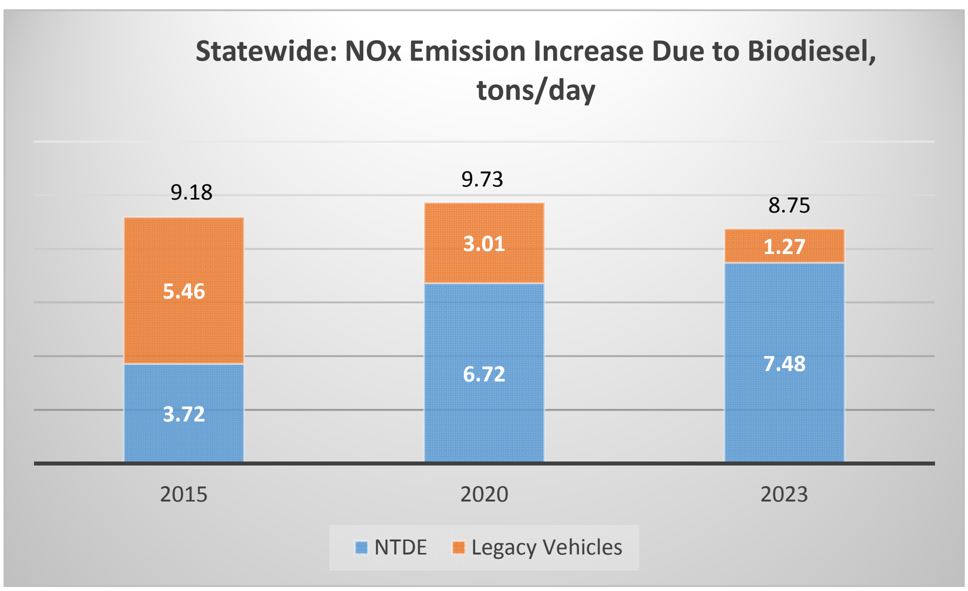


Figure 1b
Results of Sierra Analysis of South Coast Air Basin NOx Increases Due to Biodiesel Use under the Proposed ADF Regulation

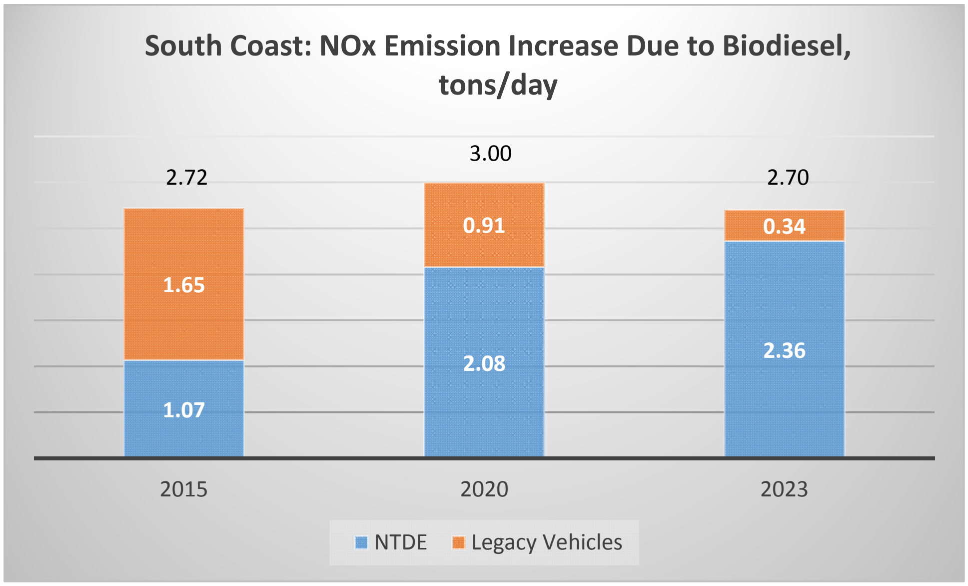
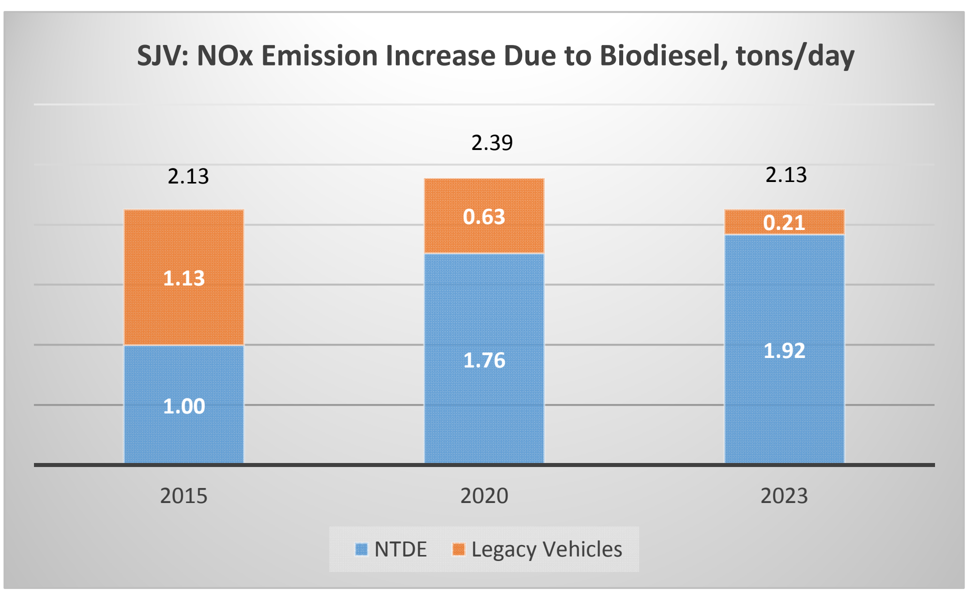


Figure 1c
Results of Sierra Analysis of San Joaquin Valley Air Basin NOx Increases Due to Biodiesel Use under the Proposed ADF Regulation



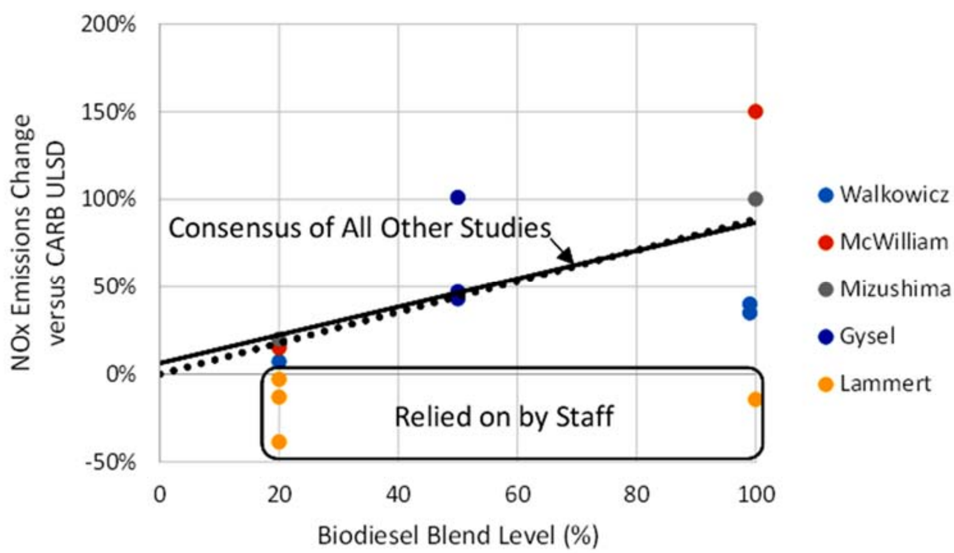
As indicated above, the Sierra analysis uses the results from an assessment of existing data regarding biodiesel impacts on NOx emissions from NTDEs performed by Rincon Ranch Consulting. The key findings of that analysis are shown in Figure 2 (reproduced with permission), which establishes that the available data for biodiesel impacts on NTDE NOx emissions follow a linear relationship just as they do for legacy vehicles.

In contrast to the data upon which the Sierra analysis rests, the basis of CARB staff's assumption regarding biodiesel impacts on NTDE emissions rests on the following excerpts from the ADF ISOR:

> *Research also indicates that the use of biodiesel up to blends of B20 in NTDEs results in no detrimental NOx impacts. Therefore, the proposed regulation also includes a process for fleets and fueling stations to become exempted from the in-use requirements for biodiesel blends up to B20 as long as they can demonstrate to the satisfaction of the Executive Officer that they are fueling at least 90 percent light or medium duty vehicles or NTDEs.*
>
> *Staff proposes to take a precautionary approach and in the light of data showing there may be a NOx impact at higher biodiesel blends but not at lower biodiesel blends, staff is limiting the conclusion of no detrimental NOx impacts in NTDEs to blends of B20 and below.*

Clearly, if CARB staff were truly taking a "precautionary approach" to the issue of biodiesel impacts on NTDE NOx emissions, they would also rely on the results of the analysis summarized in Figure 2.

Figure 2
The Impact of Biodiesel on NTDE NOx Emissions



The assumption made by CARB staff regarding biodiesel impacts on NDTE NOx emissions has additional ramifications beyond those shown above by the results of the Sierra analysis. As set forth in proposed section 2293.6, Title 13 CCR (see ISOR Appendix A), the mitigation requirements for biodiesel up to the B20 level will be dropped when NTDEs account for 90% of heavy-duty vehicle miles travelled in California (expected by staff to be 2023) and use of B20 without mitigation will be allowed in all fleets of centrally fueled vehicles comprised of more than 90% NTDEs. Given this, use of unmitigated biodiesel blends of up to B20 in NTDEs may be common under the proposed ADF regulation. The potential significance of these provisions of the staff proposal with respect to the potential for NOx increases is shown in Figures 3a through 3c, which illustrate the estimated increases in NDTE NOx emissions as a function of biodiesel content up to B20 for the state, the South Coast air basin, and the San Joaquin Valley air basins, respectively, for the years 2015, 2020, and 2023.

As shown, the potential NOx increases from extensive use of higher level biodiesel blends in NTDEs is quite large. Furthermore, although the results shown in Figures 3a through 3c are maximum potential impacts, they can again be simply scaled for other cases. For example, in order to estimate statewide NOx increases from B20 use in 50% rather than 100% of NTDEs, one would simply multiply the value of 30 tons per day by 0.5 (50/100) to arrive at a 15 ton per day increase. Finally, it should be noted that the values in Figures 3a through 3c reflect both on- and off-road NTDEs as described above for the Sierra analysis of B5 impacts.

Figure 3a
Results of Sierra Analysis of Statewide NOx Increases Due to Biodiesel Use in All NTDEs under the Proposed ADF Regulation

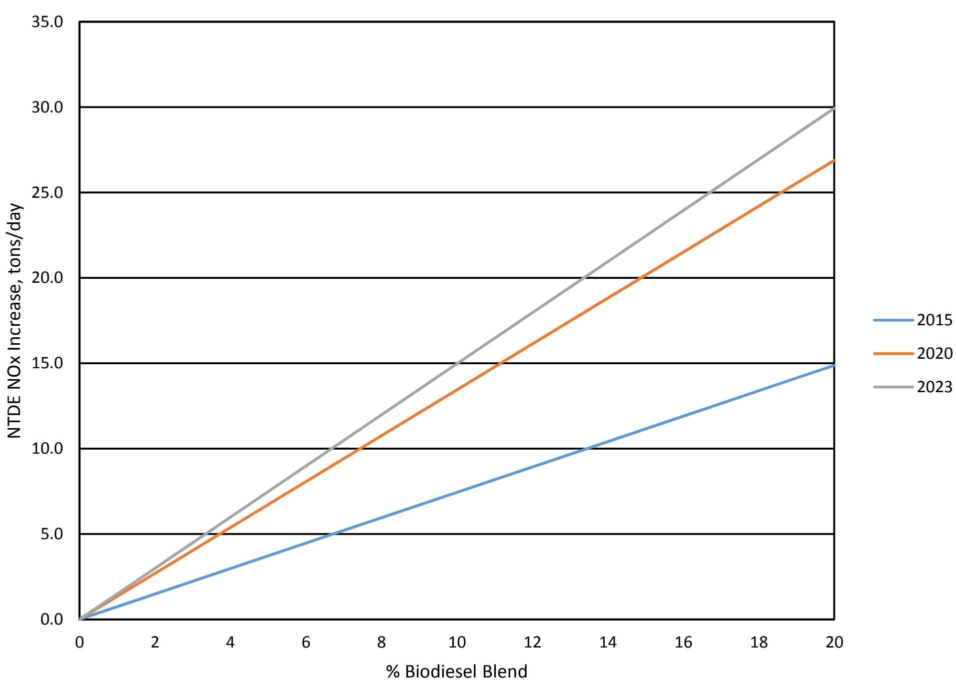


Figure 3b
Results of Sierra Analysis of South Coast Air Basin NOx Increases Due to Biodiesel Use in All NTDEs under the Proposed ADF Regulation

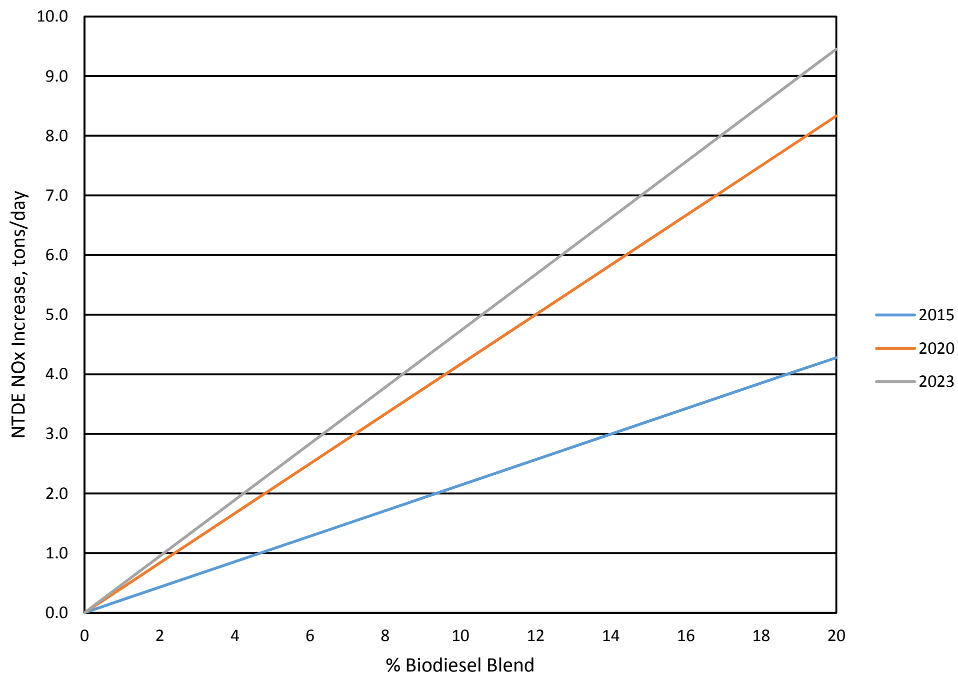
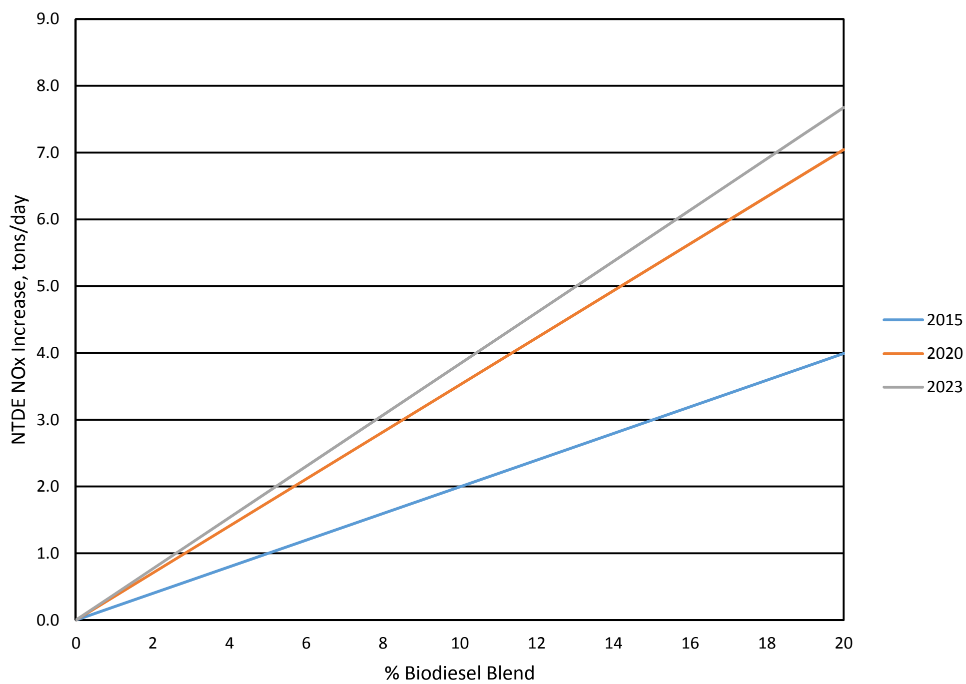


Figure 3C
Results of Sierra Analysis of San Joaquin Valley Air Basin NOx Increases Due to Biodiesel Use in All NTDEs Under the Proposed ADF Regulation



<u>Significance of Increases in NOx Emissions Caused by Biodiesel</u>

As illustrated above, the proposed ADF regulations are likely to lead to substantial increases in NOx emissions for the state as a whole, as well as in the South Coast and San Joaquin Valley air basins, which are in extreme nonattainment of the federal standard for ozone and experience the state's highest levels of ozone and other pollutants. The significance of the NOx increases from biodiesel can be seen by comparing those increases with air quality planning documents.

Perhaps the best initial point of reference comes from CARB's "Vision for Clean Air"[14] prepared in conjunction with the South Coast Air Quality Management District and the San Joaquin Valley Unified Air Pollution Control District. This report addresses potential control strategies that will be required to bring these extreme ozone nonattainment areas into compliance. According to the Vision report, NOx emissions will have to be reduced by 80% to 90% from 2010 levels in both the South Coast and San Joaquin Valley areas in order to achieve ozone compliance. Furthermore, in working to identify potential control strategies, the three regulatory agencies chose to focus <u>**only**</u> on ways to reduce NOx emissions (and not hydrocarbon emissions) because, in their words, *"NOx is the most critical pollutant for reducing regional ozone and fine particulate matter."* Given this, CARB staff's proposal to allow any NOx emission increases from the use of biodiesel is difficult to understand.

CARB staff's proposal becomes even more difficult to understand when the emission increases from biodiesel are compared to the emission benefits from adopted and proposed control measures. As an illustration, the NOx reductions expected from transportation control measures in the South Coast Basin that are part of the district's Air Quality Plan[15] are compared in Table 5 to estimated NOx emission increases under the ADF based on Sierra's analysis of B5. As shown, the increases due to biodiesel are far larger than the reductions from transportation control measures and completely offset the benefits of those measures that must be implemented as the result of their being included in the Air Quality Plan.

Table 5
Comparison of NOx Reductions from South Coast Transportation Control Measures (TCMs) and Estimated NOx Increases from Biodiesel Under the Proposed ADF Regulation

Calendar Year	NOx Reduction from TCMs, tons/day	NOx Increase due to Biodiesel tons/day
2014/2015	-0.7	2.72
2019/2020	-1.4	3.00
2023	-1.5	2.70

[14] California Air Resources Board, Vision for Clean Air: A Framework for Air Quality and Climate Planning, June 27, 2012.
[15] See South Coast 2012 AQMP. Appendix IV C. *http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-(february-2013)/appendix-iv-(c)-final-2012.pdf*

Similarly, the approximately two ton per day NOx increase estimated from the use of biodiesel in the San Joaquin Valley under the ADF can be compared to planned and implemented NOx control measures,[16,17] many of which have emission benefits on the order of two tons per day or less. Again, it should also be noted that the potential NOx emission increases allowed under the proposed ADF from extensive use of B20 in NDTEs without mitigation are far greater than the fleetwide impacts associated with the use of B5.

[16] San Joaquin Valley Air Pollution Control District, 2007 Ozone Plan and Appendices and Updates.
[17] San Joaquin Valley Air Pollution Control District, 2010 Ozone Mid-Course Review, June 2010.

Table 6
Results of Sierra Research Statewide Analysis

Statewide Total NOx Emissions Inventory, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	493.3	345.0	204.9
Construction/Mining/Drilling	75.8	56.6	43.6
Cargo Handling Equipment (CHE)	4.02	3.13	2.70
Transportation Refrigiration Units (TRU)	13.33	11.25	12.26
Agricultural Equipment	34.35	19.75	13.44
TOTAL	620.8	435.7	276.9

Statewide NTDE NOx Emissions Inventory, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	73.0	127.2	138.2
Construction/Mining/Drilling	0.8	5.5	9.0
Cargo Handling Equipment (CHE)	0.26	0.89	1.22
Transportation Refrigiration Units (TRU)	0.00	0.00	0.00
Agricultural Equipment	0.21	0.85	1.23
TOTAL	74.4	134.4	149.6

Statewide NOx Emissions Increase Due to B5 , tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	7.8550	8.5374	7.5764
Construction/Mining/Drilling	0.7916	0.7850	0.7962
Cargo Handling Equipment (CHE)	0.0506	0.0668	0.0757
Transportation Refrigiration Units (TRU)	0.1333	0.1125	0.1226
Agricultural Equipment	0.3520	0.2317	0.1837
TOTAL	9.18	9.73	8.75

Statewide NTDE NOx Emission Increase Due to B5, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	3.6523	6.3596	6.9092
Construction/Mining/Drilling	0.0424	0.2735	0.4507
Cargo Handling Equipment (CHE)	0.0131	0.0444	0.0609
Transportation Refrigiration Units (TRU)	0.0000	0.0000	0.0000
Agricultural Equipment	0.0106	0.0427	0.0617
TOTAL	3.72	6.72	7.48

Statewide Legacy Vehicle NOx Emission Increase Due to B5, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	4.2027	2.1778	0.6672
Construction/Mining/Drilling	0.7492	0.5115	0.3454
Cargo Handling Equipment (CHE)	0.0375	0.0224	0.0148
Transportation Refrigiration Units (TRU)	0.1333	0.1125	0.1226
Agricultural Equipment	0.3414	0.1890	0.1220
TOTAL	5.46	3.01	1.27

Table 7
Results of Sierra Research South Coast Air Basin Analysis

South Coast Total NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	153.0	107.9	62.3
Construction/Mining/Drilling	28.0	21.5	15.9
Cargo Handling Equipment (CHE)	3.21	2.53	2.20
Agricultural Equipment	2.18	1.23	0.84
TOTAL	186.4	133.1	81.3

South Coast NTDE NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	20.8	38.7	42.8
Construction/Mining/Drilling	0.3	2.1	3.3
Cargo Handling Equipment (CHE)	0.24	0.79	1.08
Agricultural Equipment	0.01	0.05	0.07
TOTAL	21.4	41.7	47.3

South Coast NOx Emission Increase Due to B5 , tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	2.3624	2.6270	2.3340
Construction/Mining/Drilling	0.2931	0.2993	0.2929
Cargo Handling Equipment (CHE)	0.0416	0.0568	0.0652
Agricultural Equipment	0.0223	0.0144	0.0113
TOTAL	2.72	3.00	2.70

South Coast NTDE NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	1.0410	1.9352	2.1385
Construction/Mining/Drilling	0.0161	0.1056	0.1673
Cargo Handling Equipment (CHE)	0.0118	0.0393	0.0539
Agricultural Equipment	0.0006	0.0026	0.0037
TOTAL	1.07	2.08	2.36

South Coast Legacy Vehicle NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	1.3213	0.6918	0.1955
Construction/Mining/Drilling	0.2770	0.1938	0.1256
Cargo Handling Equipment (CHE)	0.0298	0.0175	0.0112
Agricultural Equipment	0.0216	0.0118	0.0076
TOTAL	1.65	0.91	0.34

Table 8
Results of Sierra Research San Joaquin Valley Analysis

San Joaquin Valley Total NOx Emissions Inventory, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	103.9	77.1	43.9
Construction/Mining/Drilling	14.0	12.1	9.4
Cargo Handling Equipment (CHE)	0.09	0.06	0.06
Agricultural Equipment	14.81	8.58	5.82
TOTAL	132.8	97.8	59.2

San Joaquin Valley NTDE NOx Emissions Inventory, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	19.7	33.7	35.9
Construction/Mining/Drilling	0.1	1.1	1.9
Cargo Handling Equipment (CHE)	0.00	0.01	0.01
Agricultural Equipment	0.09	0.36	0.53
TOTAL	20.0	35.2	38.4

San Joaquin Valley NOx Emission Increase Due to B5 , tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	1.8277	2.1196	1.8769
Construction/Mining/Drilling	0.1459	0.1661	0.1696
Cargo Handling Equipment (CHE)	0.0010	0.0011	0.0011
Agricultural Equipment	0.1517	0.1003	0.0793
TOTAL	2.13	2.39	2.13

San Joaquin Valley NTDE NOx Emission Increase Due to B5, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	0.9857	1.6862	1.7973
Construction/Mining/Drilling	0.0075	0.0560	0.0941
Cargo Handling Equipment (CHE)	0.0001	0.0005	0.0007
Agricultural Equipment	0.0046	0.0182	0.0264
TOTAL	1.00	1.76	1.92

San Joaquin Valley Legacy Vehicle NOx Emission Increase Due to B5, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	0.8421	0.4333	0.0796
Construction/Mining/Drilling	0.1384	0.1101	0.0755
Cargo Handling Equipment (CHE)	0.0009	0.0005	0.0004
Agricultural Equipment	0.1471	0.0822	0.0529
TOTAL	1.13	0.63	0.21

Attachment E

Assessment of CARB's Environmental Analysis and ADF Mitigation Requirements

In developing the proposed Alternative Diesel Fuel (ADF) regulation, CARB staff has performed an environmental analysis and included mitigation requirements intended to eliminate the adverse environmental impacts associated with increased NOx emissions resulting from the use of biodiesel under the ADF.

The environmental analysis is fundamentally flawed in that staff incorrectly selected 2014 as the baseline year and performed the analysis in light of biodiesel usage levels in that year. As documented below, CARB staff has long been aware that biodiesel use leads to increases in NOx emissions, and promised but failed to act to address those emissions through enactment of an ADF regulation as early as 2009. There is no basis for an agency to use its failure to promptly act to address an environmental issue of which it was clearly aware as grounds to change the baseline for assessing its' proposed effort to address that issue. This is even more apparent given that CARB staff acknowledges that a key function of the LCFS regulation is to incent low carbon intensity fuels including biodiesel which has to date generated 13% of all credits issued by CARB under the LCFS.[1] Given this, the proper baseline for assessing the ADF regulation should be 2009 when CARB first stated it would regulate biodiesel use and when, by CARB staff's own admission, little biodiesel was used in California and NOx emissions were minimal.

The mitigation requirements of the ADF regulation are equally flawed. First, they are based on CARB's staff's fundamentally flawed emission analysis, and second their implementation is unreasonably delayed until 2018—more than ten years after CARB staff was aware that biodiesel use in California would lead to increased NOx emissions.

History of the ADF Regulation

Although the U.S. Environmental Protection Agency (EPA) published a report in 2002 showing that biodiesel use increases NOx emissions linearly with increasing biodiesel content,[2] the earliest document found on the CARB website indicates that agency discussions regarding the need to adopt regulations addressing NOx began at least as early as February 2004.[3] This led to the first meeting of the Biodiesel Work Group in April 2004.[4] A summary of that discussion

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[1] See Page III-2 of the LCFS ISOR.
[2] See EPA, A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions (available at http://www.epa.gov/otaq/models/analysis/biodsl/p02001.pdf).
[3] See CARB, Public Consultation Meeting Regulatory and Non-Regulatory Fuels Activities at 26-29 (Feb. 25, 2004) (available at http://www.arb.ca.gov/fuels/diesel/022504arb.pdf).
[4] See CARB Ltr. (Mar. 18, 2004) (available at http://www.arb.ca.gov/fuels/diesel/altdiesel/041204altdslwsh.pdf).

published at the time[5] it occurred indicates that topics discussed included ways to mitigate NOx emission increases associated with biodiesel use.

In 2006, CARB published a draft guidance document regarding the use of biodiesel in California,[6] at which time the agency simply decided not to address increased NOx emissions until biodiesel use became more widespread.[7] At that time, CARB instead could have ensured that there would be no NOx increases from biodiesel use by simply requiring those interested in selling biodiesel in California to demonstrate that they could formulate biodiesel blends in a way that did not increase NOx emissions, which is one of the approaches CARB is now considering.[8]

The first time CARB was scheduled to adopt regulations addressing this issue was in November 2009; this is indicated on page 12 of CARB's 2009 Rulemaking Calendar,[9] which includes the following summary:

> *Staff will propose motor vehicle fuel specifications for biodiesel and renewable diesel. These specifications are necessary for the implementation of the Low Carbon Fuel Standard regulation (to be considered at the March 2009 Hearing).*

No action was taken by CARB in 2009 and the planned adoption date was moved to June 2010; this is evidenced by CARB's 2010 Rulemaking Calendar,[10] which lists the regulatory item on page 11. This time the summary reads:

> *The staff will propose adoption of new motor vehicle fuel specifications for biodiesel and renewable diesel. These specifications are necessary to ensure that the use of these fuels will not increase emissions of criteria and toxic air pollutants when used as a motor vehicle fuel.*

Again, no action was taken by CARB in 2010 and the planned adoption date was moved to November 2011; this is evidenced by CARB's 2011 Rulemaking Calendar,[11] which lists the regulatory item on page 14. This time the summary reads:

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[5] See *CVS News*, at 27-31 (May 2004) (available at http://www.sierraresearch.com/documents/cvs_news_may_2004.pdf).
[6] See CARB, Draft Advisory on Biodiesel Use (Nov. 14, 2006) (available at http://www.arb.ca.gov/fuels/diesel/altdiesel/111606biodsl_advisory.pdf).
[7] See CARB, Suggested ARB Biodiesel Policy (May 24, 2006) (available at http://www.arb.ca.gov/fuels/diesel/altdiesel/052406arb_prsntn.pdf).
[8] See California Environmental Protection Agency, Discussion of Conceptual Approach to Regulation of Alternative Diesel Fuels (Feb. 15, 2013).
[9] See CARB, 2009 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2009rulemakingcalendar.pdf).
[10] See CARB, 2010 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2010rulemakingcalendar.pdf).
[11] See CARB, 2011 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2011rulemakingcalendar.pdf).

The Low Carbon Fuel Standard incents the use of biodiesel and renewable diesel, for which there are no current emissions–based fuel specifications. Staff will propose fuel specifications for both of these diesel blendstocks.

Yet again, no action was taken by CARB in 2011 and the planned adoption date was moved to November 2012; this is evidenced by CARB's 2012 Rulemaking Calendar,[12] which lists the regulatory item on page 14. This time the summary reads:

Rulemaking to establish commercial fuel specifications for blends of commercial diesel fuel and neat biodiesel in amounts greater than five volume percent.

Yet again, no action was taken by CARB in 2012 and, for the fourth consecutive year, the item was scheduled to be presented to the Board—the CARB Rulemaking Calendar for 2013[13] indicates on page 8 that the Board is currently scheduled to consider adoption of amendments to the agency's Alternative Diesel Fuel Regulations in September 2013. This time the summary reads:

Proposed new motor vehicle alternative diesel fuel specifications and commensurate amendments to the diesel fuel regulations.

Unlike the previous years, during 2013 CARB staff did begin to take action to actually develop a regulation that it purported would address increases in NOx emissions resulting from biodiesel use. The hearing notice[14] and Initial Statement of Reasons[15] for the proposed ADF regulation were published in October 2013, in advance of a Board hearing to be held on December 12-13, 2013. However, that hearing was postponed to until March 20, 2014,[16] and then the entire rulemaking was abandoned prior to the March 2014 hearing.[17]

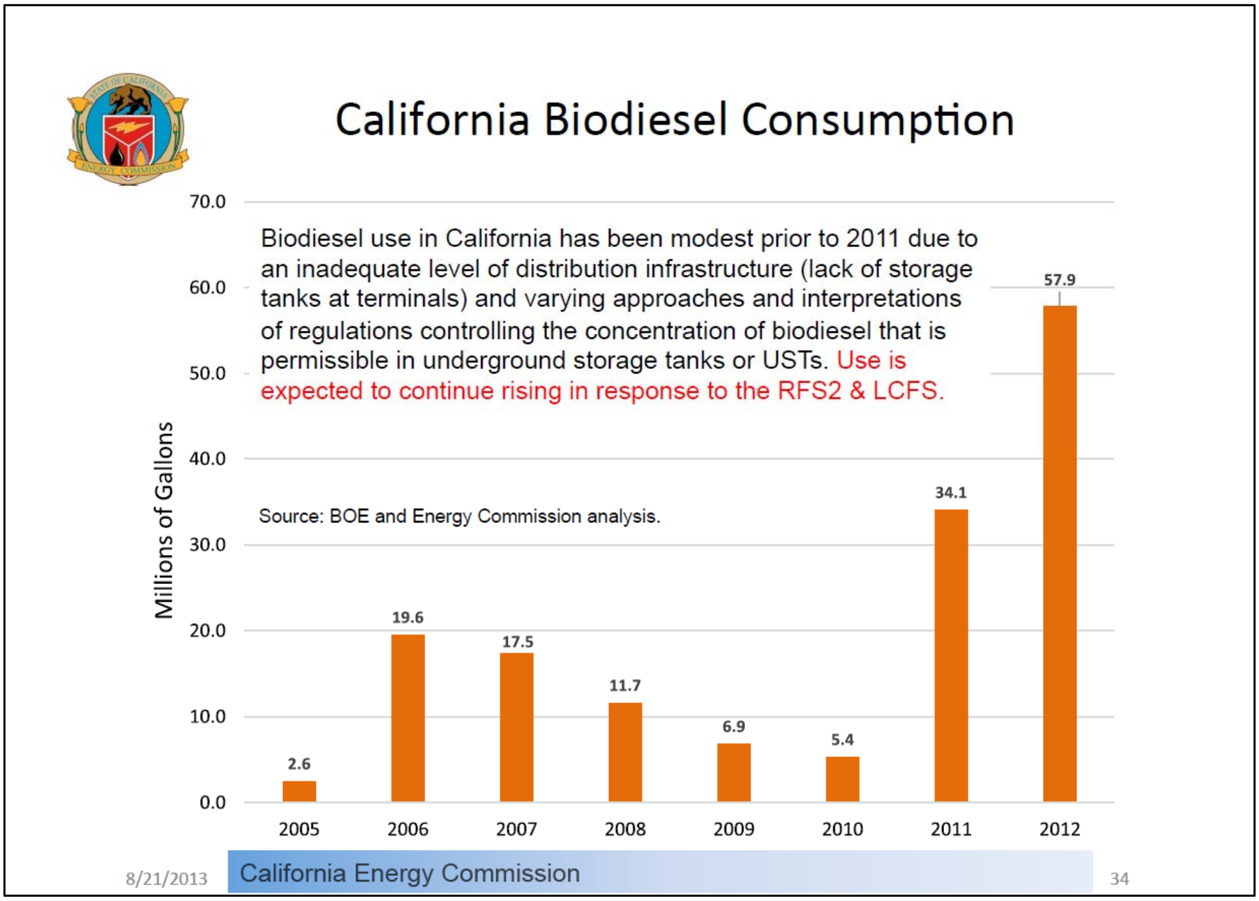
History of Biodiesel Use

Although CARB does not disclose the amounts of biodiesel used in California prior to 72 million gallons estimated in 2014 in the ADF rulemaking documents (see ISOR Appendix B), data for 2005 to 2012 are available from the California Energy Commission.[18] These data are shown in Figure 1 below. As shown, biodiesel use in California increased dramatically in 2006 when CARB staff indicated that it would not regulate biodiesel, and then decreased until the LCFS

[12] See CARB, 20012 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2012rulemakingcalendar.pdf).
[13] See CARB, 2013 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2013rmcal.pdf).
[14] See http://www.arb.ca.gov/regact/2013/adf2013/adf2013notice.pdf
[15] See http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf
[16] See http://www.arb.ca.gov/regact/2013/adf2013/adf2013postpone.pdf
[17] See http://www.arb.ca.gov/regact/2013/adf2013/NDNPadf2013.pdf
[18] See http://www.energy.ca.gov/2013_energypolicy/documents/2013-08-21_workshop/presentations/06_Schremp_Biofuels.pdf

took effect in 2011 at which point it again increased dramatically. Clearly, the appropriate baseline year for analysis of the ADF regulation is 2009 or 2010 when CARB first committed to adopting a regulation to address biodiesel NOx impacts, not any later year after which substantial increases in biodiesel use occurred in response to the LCFS.

Figure 1
Biodiesel Consumption in California as Reported by the California Energy Commission



The NOx increases resulting from CARB's failure to regulate biodiesel during the period from 2005 to 2014 are summarized in Table 1. The values presented are approximate and are based on the Sierra Research methodology for 2015 adjusted to account for differences in biodiesel use as well as the absence of NTDE engines in years prior to 2010. Biodiesel use for 2014 is taken from Appendix B of the ADF ISOR, and the estimated use for 2013 assumed linear growth in biodiesel use from 2012 to 2014. Significant increases in NOx emissions from 2011 to 2014 can be seen from a comparison of the values presented in Table 1 with the values presented in Table B-1 of Appendix B to the ADF ISOR. These increased NOx emissions from 2011 to 2014 total 782, 1032, and 3,463 tons for the San Joaquin Valley, South Coast, and entire state, respectively.

Table 1 Estimated Increases in NOx Emissions Due to Biodiesel Use in California from 2005 to 2014 (tons per year)			
Calendar Year	Statewide	South Coast	San Joaquin Valley
2005	31	9	7
2006	234	70	50
2007	209	63	45
2008	140	42	30
2009	82	25	18
2010	65	19	14
2011	447	134	98
2012	825	246	184
2013	1000	298	227
2014	1191	354	273
Total	4225	1260	945

Proposed ADF Mitigation Requirements

Under the proposed ADF regulation,[19] mitigation is generally required for "low-saturation" biodiesel blends with diesel fuel above B5 (e.g., B6 and higher) during the summer, and above B10 (e.g., B11 and higher) during the winter, unless the fuels are used in vehicles with new technology diesel engines in which case mitigation is not required for levels up to B20. For "high-saturation" biodiesel blends with diesel fuel, mitigation is required year-round above B10 (e.g., B11 and higher) again, unless the fuels are used in vehicles with new technology diesel engines in which case mitigation is not required for levels up to B20. However, no mitigation is required for any biodiesel blend sold in California prior to January 1, 2018.

According to the ADF ISOR,[20] CARB staff selected these levels based on an "analysis" for which no detail or documentation has been provided, and that reportedly included consideration of the impacts of new technology diesel engines (NTDEs) and the use of renewable diesel as "offsetting factors." Although it is impossible to thoroughly review an analysis which is not described in detail, in this case it can still be demonstrated to be fundamentally flawed. As discussed elsewhere, CARB incorrectly assumes that NOx emissions from NTDEs are unaffected by biodiesel despite the fact that available data show statistically significant increases in NOx emissions. Further, CARB cannot rely on the use of renewable diesel as mitigation for NOx increases from biodiesel as there is nothing in the ADF or the LCFS regulation that mandates the use of any volume of renewable diesel in California, nor which links the amount of renewable diesel used to the amount of biodiesel used. Further, neither the ADF nor LCFS regulations ensure that fuel producers will use biodiesel in a manner that provides surplus

[19] Proposed section 2293.6 Title 13, CCR in ISOR Appendix A.
[20] Chapter 6, Part H.

reductions[21] in NOx emissions. Given that CARB's reliance on "offsetting factors" is fundamentally flawed, the agency's "Determination of NOx Control Level for Biodiesel" is also fundamentally flawed. Another problem with the "determination" is that CARB staff claims to have performed an "analysis" for which no detail or documentation is provided, indicating that the higher blend level threshold for mitigation that applies to "low-saturation" blends during the winter months will not result in adverse air quality impacts. Again, it is not possible to critically review an analysis which is not described in detail; further, the information provided in this analysis is so insufficient that it is not even possible to develop an appropriate set of comments.

In addition to the flaws in CARB staff's analysis of what mitigation should be applied to address the increased NOx emissions associated with biodiesel use, CARB staff is arbitrarily delaying the date on which mitigation is required by two years from the expected effective date of the ADF regulation. According to ADF ISOR, CARB staff claim the reason for this delay is:

> *ARB is also proposing the in-use requirements come into effect on January 1, 2018, as time is needed to overcome logistical and other issues in implementation of in-use requirements. For example, use of the additive Di-tert-butyl peroxide (DTBP) will require replacement of steel tanks with stainless steel tanks, permitting of hazardous substance storage, approval by local fire agencies, additional additization infrastructure, and logistical business changes to acquire the additive. All of this is expected to take around 2 years to complete. Another method of compliance is re-routing higher blends to NTDEs. Research shows that the use of biodiesel in blends up to B20 in NTDEs results in no detrimental NOx impacts. This and other methods of complying with the in-use requirements, such as certification of additional options are also expected to take 2 years or more. Because compliance with the in-use options would be infeasible during initial implementation on January 1, 2016, only recordkeeping and reporting provisions will be implemented initially. The in-use requirements are proposed to come into effect on January 1, 2018.*

It is not clear why CARB staff believes that a two year delay in the implementation of mitigation requirements is required under the ADF regulation when the maximum delay in the implementation of new requirements under the LCFS regulation, which will much more dramatically impact fuel producers than the ADF requirements, is only one year, until January 1, 2017. Further, as the biodiesel industry has been on notice that CARB intended to impose NOx mitigation requirements for over ten years, it is not clear why such measures cannot be required from the expected January 1, 2016 effective date of the proposed regulation.

The impact of the failure to immediately require Biodiesel mitigation under the ADF regulation is shown in Table 2. These values are based on the Sierra Research emissions methodology which assumes statewide use of B5. As discussed elsewhere, these impacts

[21] In order to generate surplus reductions in NOx, renewable diesel would have to be blended into diesel fuel downstream of refineries, and although CARB staff has assumed that this will occur they have provided no basis for that assumption.

are significant in that the increases are as large or larger than those sought from emission control measures implemented of under consideration by CARB and local air pollution control agencies in the South Coast and San Joaquin Valley air basins.

Table 2
Potential NOx Increases Due to CARB's Failure to Require Immediate Biodiesel Mitigation Under the ADF
(tons per year)

	Statewide	South Coast	San Joaquin Valley
2016	3405	1013	796
2017	3460	1034	815
Total	6866	2047	1612

Attachment F

Potential for Actual Biodiesel Blend Levels to Exceed Levels Purported Under the Proposed ADF Regulation

In order to properly understand and mitigate the adverse environmental impacts of biodiesel blends sold in California, it is critical that the actual amount of biodiesel present in a blend be accurately known. Despite this, the proposed ADF regulation fails to adequately ensure that the actual biodiesel content of biodiesel blends—and therefore their adverse environmental impacts—will be accurately known or appropriately mitigated. As discussed below, significant changes are required to definitions used in the proposed LCFS and ADF regulations, and new testing, recordkeeping, and reporting requirements need to be added to the ADF regulation to prevent the blending of biodiesel with fuels that already contain undisclosed amounts of biodiesel.

Background

CARB regulations at §2281 and §2282, Title 13, California Code of Regulations apply to vehicular diesel fuel sold in California and define "diesel fuel" as follows:

> *"Diesel fuel" means any fuel that is commonly or commercially known, sold or represented as diesel fuel, including any mixture of primarily liquid hydrocarbons – organic compounds consisting exclusively of the elements carbon and hydrogen – that is sold or represented as suitable for use in an internal combustion, compression-ignition engine."*[1]

The proposed LCFS regulation contains the following definitions that are relevant to biodiesel blends (See ISOR Appendix A):[2]

> *"B100" means biodiesel meeting ASTM D6751-14 (2014) (Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels), which is incorporated herein by reference.*
>
> *"Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel meeting all the following:*

[1] 13 CCR §2281(b)(1) and §2282(b)(3)
[2] See proposed §95481, Title 17, California Code of Regulations

(A) Registered as a motor vehicle fuel or fuel additive under 40 Code of Federal Regulations (CFR) part 79;
(B) A mono-alkyl ester;
(C) Meets ASTM D6751-08 (2014), Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, which is incorporated herein by reference;
(D) Intended for use in engines that are designed to run on conventional diesel fuel; and
(E) Derived from nonpetroleum renewable resources.

"Biodiesel Blend" means a blend of biodiesel and diesel fuel containing 6 percent (B6) to 20 percent (B20) biodiesel and meeting ASTM D7467-13 (2013), Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), which is incorporated herein by reference.

"Diesel Fuel" (also called conventional diesel fuel) has the same meaning as specified in California Code of Regulations, title 13, section 2281(b).

"Diesel Fuel Blend" means a blend of diesel fuel and biodiesel containing no more than 5 percent (B5) biodiesel by weight and meeting ASTM D975-14a, (2014), Standard Specification for Diesel Fuel Oils, which is incorporated herein by reference.

Finally, the proposed ADF regulation contains the following definitions that are relevant to biodiesel blends:[3]

"Alternative diesel fuel" or "ADF" means any fuel used in a compression ignition engine that is not petroleum-based, does not consist solely of hydrocarbons, and is not subject to a specification under subarticle 1 of this article.

"Biodiesel" means a fuel comprised of mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats that is 99-100 percent biodiesel by volume (B100 or B99) and meets the specifications set forth by ASTM International in the latest version of Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels D6751 contained in the ASTM publication entitled: Annual Book of ASTM Standards, Section 5, as defined in California Code of Regulations, title 4, section 4140(a), which is hereby incorporated by reference.

"Biodiesel Blend" means biodiesel blended with petroleum-based CARB diesel fuel or non-ester renewable diesel.

[3] See proposed §2293.2(a), Title 13, California Code of Regulations

"Blend Level" means the ratio of an ADF to the CARB diesel it is blended with, expressed as a percent by volume. The blend level may also be expressed as "AXX," where "A" represents the particular ADF and "XX" represents the percent by volume that ADF is present in the blend with CARB diesel (e.g., a 20 percent by volume biodiesel/CARB diesel blend is denoted as "B20").

"B5" means a biodiesel blend containing no more than five percent biodiesel by volume.

"B20" means a biodiesel blend containing more than five and no more than 20 percent biodiesel by volume.

"CARB diesel" means a light or middle distillate fuel that may be comingled with up to five (5) volume percent biodiesel and meets the definition and requirements for "diesel fuel" or "California nonvehicular diesel fuel" as specified in California Code of Regulations, title 13, section 2281 et seq. "CARB diesel" may include: non-ester renewable diesel; gas-to-liquid fuels; Fischer-Tropsch diesel; diesel fuel produced from renewable crude; CARB diesel blended with additives specifically formulated to reduce emissions of one or more criteria or toxic air contaminants relative to reference CARB diesel; and CARB diesel specifically formulated to reduce emissions of one or more criteria or toxic air contaminants relative to reference CARB diesel.

Discussion

The first issue related to the potential for uncertainty and inaccuracy in actual biodiesel content of fuels sold in California involves the different definitions that have been proposed for the term "biodiesel" under the proposed LCFS and ADF regulations. Although the two definitions may be functionally equivalent, they should be made the same under both the LCFS and ADF regulations unless CARB staff can articulate a compelling need for the use of different definitions to describe the same thing.

More importantly, the term "Biodiesel Blend" in the proposed LCFS regulation directly conflicts with the use of the same exact term in the proposed ADF regulation: a "Biodiesel Blend" under the LCFS regulations contains at least 6% biodiesel, while a "Biodiesel Blend" under the ADF is a diesel fuel containing any biodiesel. Furthermore, the LCFS regulation defines "Diesel Fuel Blend" as a blend of diesel fuel and up to 5% biodiesel, while such a fuel would be considered "CARB diesel" under the ADF regulation. Again, this haphazard use of the same term to describe fundamentally different fuels and different terms to describe the same fuel will assuredly lead to confusion in practice regarding the actual content of biodiesel available in California.

Further confusion is created by the definitions of "Biodiesel Blend" and "Blend Level" under the proposed ADF regulation. "Biodiesel Blend" is defined as a mixture of biodiesel and an undefined fuel referred to as "petroleum-based CARB diesel." "Blend

Level" applies to blends of all fuels subject to the ADF regulation, including biodiesel, and is defined as the ratio of an "Alternative diesel fuel" mixed with "CARB diesel." However, as noted above, "CARB diesel" may already contain as much as 5% biodiesel under the proposed ADF regulation. Furthermore, the definition of "Blend Level" includes no reference to the fuel termed "petroleum-based CARB diesel" that appears in the definition of "Biodiesel Blend" under the ADF—instead, it refers to "CARB diesel," which, as noted above, may contain as much as 5% biodiesel. Obviously, the addition of biodiesel to a fuel already containing some amount of biodiesel up to 5% will cause the actual biodiesel content to be higher than the blender expects; this, in turn, will lead to more significant adverse environmental impacts than expected. It is also clear that CARB staff mean for the definition of "Blend Level" to apply to "Biodiesel Blends," as that definition uses an example based on biodiesel (B20) to demonstrate the practical meaning of "Blend Level."

Finally, under the proposed ADF regulation, "B20" is nonsensically defined as a fuel that contains between 6% and 20% biodiesel, which directly contradicts the definition of "Blend Level" in same regulation. There appears to be no need for this definition or the definition of B5 in the proposed ADF regulation.

As outlined above, the proposed CARB LCFS and ADF regulations fail completely in clearly defining the four fuels that are of fundamental importance to ensuring that the biodiesel content of a fuels sold in California—and hence the adverse environmental impacts associated with their use—is accurately known. Instead, the proposed regulations make it likely that biodiesel blenders will unknowingly use fuels that already contain an unknown amount of biodiesel (up to 5%) in blending and that the actual biodiesel content of biodiesel blends may be as much as 5% greater than that represented by the blender and reported to CARB under the ADF regulation. This is significant because, as discussed in other attachments to this declaration, the increases in NOx emissions and associated adverse environmental impacts caused by biodiesel blends become larger in direct proportion to the amount of biodiesel present.

Both the LCFS and the ADF regulation must clearly define the four fuels described below.

1. ***"Diesel fuel"* –** This should defined as under 13 CCR §2281(b)(1) and §2282(b)(3).

2. ***"Biodiesel"*** or "***B100"* –** It appears that this could be properly defined through changes to the definitions currently proposed in the LCFS and ADF regulations; this is what should be blended only with "diesel fuel" to create a "Biodiesel Blend."

3. ***"CARB diesel"* –** This is accurately defined under the proposed ADF regulation, but under no circumstances should it be allowed to be blended with biodiesel or any other ADF. It should be renamed to clearly differentiate it from "diesel fuel" such that no reasonable person would understand that it could be legally mixed with any ADF.

4. ***"Biodiesel Blend"* –** This should refer to the "Blend Level" and must correspond to the actual amount of "Biodiesel" or "B100" in terms of percentage by volume in the final blend with "diesel fuel."

In addition to modifying the definitions as described above, the ADF regulation must also be modified to ensure that biodiesel blenders do not intentionally or unintentionally blend biodiesel into fuels that already contain biodiesel. This can easily be achieved by adding requirements to proposed §2293.8 Title 13, CCR, to require that any "diesel fuel" to be used in blending with biodiesel be tested for the presence of biodiesel prior to blending. Similarly, that section should be modified to include reporting and record keeping requirements for biodiesel blenders that document that they have used only biodiesel-free "diesel fuel" in all of their blending operations.

Attachment G

The Growth Energy Alternative to Proposed ADF Regulation is the Least-Burdensome Approach that Best Achieves the Project Objectives at the Least Cost That Must be Adopted

As part of the rulemaking process leading to CARB staff's proposed ADF regulation, staff was required to solicit and consider alternatives to the proposed regulation. Growth Energy submitted such an alternative which CARB staff acknowledged provided equivalent or superior reductions in NOx emissions from biodiesel use but rejected as being more costly. However, as is documented in detail below, CARB staff made fundamental errors in its' assessment of the Growth Energy Alternative, which will in fact provide greater reductions in NOx emissions from biodiesel use than the staff's proposed ADF regulation but do so with equal cost-effectiveness. (Equal cost-effectiveness means that the dollars spent per unit mass of NOx emissions eliminated will be the same.) Given that the Growth Energy alternative provides greater environmental benefits, which in turn substantially lessen the ADF's significant impacts, and is equally cost-effective as the staff's proposed ADF regulation, the Growth Energy Alternative rather than the staff proposal should be adopted by CARB.

Background

On July 29, 2014, CARB published a "Solicitation of Alternatives for Analysis in the Alternative Diesel Fuel Standardized Regulatory Impact Assessment" which is attached. On August 15, 2014, Growth Energy submitted an alternative regulatory proposal for the ADF regulation (which is attached) to CARB in response to the agency's solicitation. On December 30, 2014, CARB staff published both the ISOR for the ADF regulation as well as a document entitled "Summary of DOF Comments to the Combined LCFS/ADF SRIA and ARB Responses" which is Appendix E to the ADF ISOR, both of which include information related to staff's decision to reject the alternative to the ADF regulation proposed by Growth Energy.

The staff's assessment of the Growth Energy (GE) Alternative published in Appendix E of the ADF ISOR is as follows (emphasis added):

> ***Benefits:***
>
> ***ARB finds that the GE alternative would meet the emissions goals of the ADF proposal and achieve roughly the same emissions benefits as the ADF proposal. The GE alternative may achieve marginally more emissions benefits if biodiesel were to be widely used as an additive under the ADF proposal. Although the GE alternative is simpler than the ADF proposal, the GE alternative is unnecessarily strict; ARB's analysis of the science does not find that there are NO_X increases with B5 animal biodiesel or biodiesel used in NTDEs, so***

> ***requiring mitigation for these does not achieve any additional emissions benefit versus the ADF proposal.***
>
> ***Costs:***
>
> *The GE alternative would require mitigation of more fuel than the ADF proposal; regulated parties would incur more costs to mitigate non-animal- and animal-based biodiesel similarly and setting the significance level for both at one percent. Additionally, the NTDE exemption would increase the volumes of fuels to be mitigated, further increasing the direct costs on regulated parties.*
>
> ***Economic Impacts:***
>
> *The REMI results also indicate that the combined LCFS/ADF proposal has no discernible difference from the GE alternative. Employment, GSP, and output differ only slightly and represent a difference of less than one tenth of one percent. Given that the GE alternative has higher direct costs, the combined LCFS/ADF alternative is preferred.*
>
> ***Cost-Effectiveness:***
>
> *The GE alternative costs more than the ADF proposal, because it requires mitigation of more biodiesel than the ADF proposal. The GE alternative does not result in any more emissions reductions than the ADF proposal and as such is less cost effective than the ADF proposal.*
>
> ***Reason for Rejection:***
>
> ***ARB rejects the GE alternative because it costs more than the ADF proposal and does not achieve additional emissions benefits****.*

The reason for rejection of the Growth Energy (GE) alternative presented in the ADF ISOR itself is as follows:

> ***This alternative proposal retains the same biodiesel NOx mitigation options as the ADF proposal****. However, under the GE alternative, animal and non-animal biodiesel would be treated equally and require NOx mitigation for all biodiesel blends, including blends below B5.* ***ARB rejects this alternative because the costs are significantly higher than the ADF proposal and do not achieve additional emissions benefits.*** *During the development of this regulation, staff considered alternatives to the proposal and determined that the proposal represents the least-burdensome approach that best achieves the objectives at the least cost.*

Finally, it should be noted that the stated intention of the ADF regulation according to CARB staff in the ADF ISOR is as follows (emphasis added):

> *The ADF regulation is intended to create a framework for these low carbon diesel fuel substitutes to enter the commercial market in California,* ***while mitigating any potential environmental or public health impacts****.*

Discussion

As indicated above, the stated reason why CARB staff rejected the Growth Energy alternative to the proposed ADF regulation is because CARB staff believed it would require that actions be taken to mitigate increased NOx emissions from biodiesel under circumstances where CARB staff incorrectly assumed there would no increased emissions due to biodiesel use on under the ADF. However, as is clearly demonstrated in another attachment to the declaration of James M. Lyons,[1] CARB staff's analysis and assumptions of the increases in NOx emissions that will result for the ADF regulation is fatally flawed as is CARB's basis for rejection of the Growth Energy Alternative.

As shown by the Sierra emissions analysis, once the flaws in the CARB emissions analysis are corrected, it becomes clear that the ADF regulation will allow significant and unmitigated increases in NOx emissions to occur throughout California including areas such as the South Coast and San Joaquin air basins which experience the worst air quality in the state. As CARB staff itself admits, the Growth Energy alternative would require mitigation in exactly those areas where CARB staff was lead to believe it was not required based on its flawed emissions analysis. CARB staff also admits the Growth Energy alternative is based on the same mitigation options contained in the ADF regulation, which CARB staff has already determined to be technically feasible and cost-effective. However, the Growth Energy Alternative is superior to the ADF regulation because it expands the conditions under which this mitigation has to be applied in order to eliminate the potential for any increase in NOx emissions due to biodiesel use to a less-than-significant level. The Growth Energy Alternative therefore precludes any adverse environmental impacts due to increased NOx emissions, which is exactly what CARB staff has asserted the ADF regulation is intended to do.

Given that the Growth Energy alternative:

1. Provides complete mitigation of potential NOx emission increases due to biodiesel use under the ADF and any associated adverse environmental impacts; and

2. Relies on the same mitigation strategies proposed by CARB staff which staff has found to be technically feasible and cost-effective,

CARB must adopt the Growth Energy alternative as it better achieves the stated project objectives in an equally cost-effective manner.

[1] Review of CARB Staff Estimates of NOx Emission Increases Associated with the Use of Biodiesel in California under the Proposed ADF Regulation.

Appendix J

Appendix J

Additional Analysis Required Under the California Environmental Quality Act

A. <u>CARB May Not Ignore the LCFS Regulation's Pre-2015 Impacts</u>

CARB Staff initiated the environmental review process for the LCFS regulation in 2007, and circulated an Initial Statement of Reasons for the proposed regulation in 2009. As explained by the Court in *POET, LLC v. California Air Resources Board* (2013) 218 Cal.App.4th 681 ("*POET*"), CARB subsequently approved that regulation on April 24, 2009, without completing the environmental review process, and impermissibly delegated authority to complete the environmental review process to the Executive Officer. The Court found that CARB's actions violated CEQA, and directed the superior court to issue a writ enjoining enforcement of the LCFS regulation beyond 2013 levels. The writ issued by the superior court requires CARB, prior to its consideration of the LCFS regulation, to evaluate "the potential adverse environmental effect of increased NOx emissions" associated with the "project" (*i.e.*, the LCFS regulations presently being enforced). (Exhibit "1.") To this day, CARB has never performed a legally compliant review of the environmental effects of CARB's existing LCFS regulation.

Although the court in *POET* directed CARB to evaluate the effects of the LCFS regulation, the Environmental Assessment ("EA") for the LCFS regulation and the ADF regulation (the "Proposed Regulations") ignores the impacts of the LCFS regulation presently in effect, as well as any other impacts of the project prior to 2014. As a result, prior to its consideration of the LCFS regulation and the ADF regulation, CARB must substantially revise and recirculate the EA for public review to evaluate the entire project.

1. CARB's Project Description Is Inadequate Because it is Unclear <u>Whether the Existing LCFS Regulation Is Part of the Project</u>

"An accurate, stable and finite project description is the sine qua non of an informative and legally sufficient" environmental document. (*County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 193.) Additionally, the ***entire project*** being proposed must be described in the EIR, and the project description must not minimize project impacts. (*City of Santee v. County of San Diego* (1989) 214 Cal.App.3d 1438, 1450.) As explained in *County of Inyo*:

> A curtailed or distorted project description may stultify the objectives of the reporting process. Only through an accurate view of the project may affected outsiders and public decision-makers balance the proposal's benefit against the environmental cost, consider mitigation measures, assess the advantage of terminating the proposal (*i.e.*, the "no project" alternative) and weigh other alternatives in the balance.

(*County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 192-93.)

The EA violates this mandate. First, the EA is unclear as to whether CARB is treating the "Project" as including the LCFS regulation presently in effect. On the one hand, the EA's project description discusses the existing LCFS regulation; the EA recognizes that the present action is being taken in response to the decision in *POET*; and the "re-adopted" LCFS regulation is structurally nearly identical to the LCFS regulation presently being enforced. On the other hand, however, the EA does not address the environmental effects of the LCFS regulation presently being enforced, and the "carbon intensity" base year has changed from 2010 to 2014. Because it is unclear whether the "project" analyzed in the EA includes the LCFS regulation presently in effect, the project description in the EA is not stable or finite, and is thus inadequate under CEQA.

To the extent CARB intended to omit the current LCFS regulation from the project description, that action would also result in an inadequate project description because it is "inaccurate." CEQA requires the project description to include ***entire project***, not a smaller piece of the project that would have the impact of minimizing project impacts. (*City of Santee*, *supra*, 214 Cal.App.3d at 1450.) Describing only the "re-adopted" portions of the LCFS regulation also runs directly contrary to the writ issued by the superior court, which specifically requires CARB to analyze the effects of the project presently being implemented. (See Exhibit "1.")

As a result, CARB must revise the project description in the EA to specifically include the existing LCFS regulation, and analyze the impacts associated with the existing regulation.

2. <u>The Baseline Used By CARB Is Unclear</u>

Because the impacts of a project are evaluated against the environmental baseline, determining the proper baseline is critical to a meaningful discussion of the project's environmental impacts. (See *Communities for a Better Environment v. South Coast Air Quality Mgmt. Dist.* (2010) 48 Cal.4th 310, 320.) The EA here obscures the baseline used by CARB for its analysis of the impacts of the regulations because there is no definitive statement explaining what specific baseline is being used in the EA. Rather, the portion of the EA that purportedly sets forth the baseline cites to an appendix to the EA, which discusses the "Environmental and Regulatory Setting" of the Regulations. But even this appendix does not specifically state what date the EA is using as the baseline for environmental review. As a result, the EA should be revised to specifically state what baseline it is using, and recirculated for public review.

3. <u>Ignoring Pre-2014 Impacts Results in an Improper Baseline for Environmental Review</u>

Generally, the "environmental baseline" includes the environmental conditions as they exist at the time the lead agency publishes the Notice of Preparation ("NOP") for the project, or, if there is no NOP, as is the case here, "at the time the environmental analysis is commenced." (CEQA Guidelines, § 15125(a).) Although the EA does not specifically state what baseline is being used, the analysis in the EA ignores the LCFS regulation's impacts prior to 2014, and asserts that the analysis in the EA "addresses the potentially significant adverse environmental impacts resulting from implementing the proposed LCFS and ADF regulations

compared to existing conditions, **which include existing compliance with the LCFS left in place by the Court at the 2013 regulatory standards**." (EA at 3 [emphasis added].)

Omitting analysis of the project's pre-2014 impacts is improper. Here, the environmental review commenced in 2007, and the initial Staff Report/ISOR for the LCFS regulation was released in 2009. As a result, the proper baseline for environmental review under CEQA is 2007, and certainly no later than 2009. (CEQA Guidelines, § 15125(a).)

To the extent CARB intends to use a baseline of 2014, that baseline is also impermissible because it is "misleading" and obscures the impacts of the Regulations. (See, e.g., *Neighbors for Smart Rail v. Exposition Metro Line Construction* (2013) 57 Cal.4th 439.) Specifically, NOx emissions caused by the existing LCFS regulation from 2011 through 2014 from the San Joaquin Valley, the South Coast air basin, and the entire state, respectively, total 782, 1,032, and 3,463 tons per year. (Decl. Lyons at E-4.) Because a 2014 baseline has the effect of essentially sweeping prior NOx emissions under the rug, it is misleading, and a more accurate baseline should be used.

The fact that the emissions occurred in the past does not excuse CARB from analyzing the effects of those emissions, as CARB still has the ability to mitigate these emissions, or modify the LCFS regulation in response to its analysis. In *Bakersfield Citizens for Local Control*, for example, the court set aside an EIR for a large commercial development, including a Wal-Mart. The trial court enjoined the construction of the Wal-Mart, but let the remainder of the construction proceed, and those businesses were operating at the time the court of appeal heard the case. The agency asserted the environmental review for the other businesses was moot because those businesses were operational. The Fifth District Court of Appeal disagreed, finding:

> [E]ven at this late juncture full CEQA compliance would not be a meaningless exercise of form over substance. The City possesses discretion to reject either or both of the shopping centers after further environmental study and weighing of the projects' benefits versus their environmental, economic and social costs. As conditions of reapproval, the City may compel additional mitigation measures or require the projects to be modified, reconfigured or reduced. The City can require completed portions of the projects to be modified or removed and it can compel restoration of the project sites to their original condition.

(*Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1204.) In other words, "[a]s a matter of public policy and basic equity, developers should not be permitted to effectively defeat a CEQA suit merely by building out a portion of a disputed project during litigation . . . ." (*Id.* at 1203.) By ignoring pre-2014 NOx emissions, CARB is seeking to do just that.[1]

[1] CARB also cannot rely upon the rule that the baseline for a previously-reviewed project assumes the previously-approved project exists. (See Remy, Thomas, Moose & Manley, *Guide to CEQA* (11th ed. 2007) at 207.) This is because the Court in *POET, LLC v. California Air Resources Board* invalidated CARB's environmental document for the original LCFS regulation.

Because the EA employs the wrong baseline, the EA should be revised, and recirculated for public review.

4. **By Failing to Address Pre-2014 NOx Emissions, the EA Is Deficient Because it Does Not Analyze Cumulative Impacts**

Even if CARB could argue the existing LCFS regulation was a different "project" under CEQA, CARB in its EA would still need to address the impacts of that regulation as "cumulative impacts." This is because CEQA requires that the environmental document discuss the cumulative effect on the environment of the subject project in conjunction with other closely-related ***past***, present, and reasonably foreseeable probable future projects. (See, e.g., Pub. Resources Code, § 21083, subd. (b).) "The purpose of this requirement is obvious: consideration of the effects of a project or projects as if no others existed would encourage the piecemeal approval of several projects that, taken together, could overwhelm the natural environment and disastrously overburden the man-made infrastructure and vital community services. This would effectively defeat CEQA's mandate to review the actual effect of the projects upon the environment." (*Citizens to Preserve the Ojai v. County of Ventura* (1985) 176 Cal.App.3d 421, 432.) Thus, regardless of whether the original LCFS regulation and the proposed LCFS regulation constituted different projects, CARB cannot avoid analyzing pre-2014 impacts as cumulative impacts.

5. **CARB's Failure to Analyze Pre-2014 Impacts Constitutes Improper Segmentation/Piecemealing**

Ignoring the impacts of the existing regulation also impermissibly piecemeals the analysis of the impacts of the LCFS regulation. CEQA prohibits a lead agency from piecemealing – or segmenting – the environmental review of a project; in other words, a lead agency may not break up an action into several small "projects" that would have the effect of minimizing environmental review. "The requirements of CEQA cannot be avoided by piecemeal review which results from "chopping a large project into many little ones-each with a minimal potential impact on the environment-which cumulatively may have disastrous consequences." (*Lighthouse Field Beach Rescue v. City of Santa Cruz* (2005) 131 Cal.App.4th 1170, 1208-09 [quoting *Bozung v. LAFCo* (1975) 13 Cal.3d 263, 283-84]; see also *Environmental Protection Info. Ctr. v. Calif. Dept. of Forestry & Fire Prot.* (2008) 44 Cal.4th 549, 503.) In other words, where "an individual project is a necessary precedent for action on a larger project," the environmental review performed by the public agency "***must*** address itself to the scope of the larger project." (Cal. Code Regs., § 15165 [emphasis added].)

As explained previously, NOx emissions caused by the LCFS regulation from 2011 through 2014 from the San Joaquin Valley, the South Coast air basin, and the entire state, respectively, total 782, 1,032, and 3,463 tons per year. (Decl. Lyons at E-4.) These past emissions – caused directly by the LCFS regulation that remains in effect – are troubling, due to among other things the U.S. EPA's recent redesignation of the San Joaquin Valley as an "extreme" non-attainment area for NOx. (75 Fed. Reg. 24409.) Estimated NOx emissions in the San Joaquin Valley caused by the existing version of the LCFS regulation total approximately 2.39 tons per day (or 872.35 tons per year) in 2020. (Decl. Lyons at D-10 [Figure 1c], F-18 [Table 8].) This is far higher than the San Joaquin Valley Air Pollution Control District's (the "District") adopted threshold of significance for NOx, which explain that a "project" under

CEQA is considered to have a significant impact on air quality if it would cause NOx emissions to exceed 10 tons per year.[2]

The EA makes no mention of these past increases, despite the fact that under the proposed LCFS regulation considered for "re-adoption" and the ADF regulation, statewide NOx emissions from biodiesel are projected to increase. (ADF ISOR at 42.) To fully consider and evaluate the potential significant impacts of the LCFS regulation and the ADF regulation, CARB may not look at the post-2014 emissions in isolation. Rather, by "chopping" the LCFS regulation into two smaller pieces, and obscuring the environmental impacts of the Regulations in the process, CARB is seeking to impermissibly piecemeal environmental review of the project. (*Lighthouse Field, supra*, 131 Cal.App.4th at 1208-09.)

B. The EA's Analysis of Criteria Pollutant Emissions, Including NOx, Is <u>Incomplete</u>

NOx is one of the most important smog-forming emissions from man-made sources in some areas of California, including the San Joaquin Valley. Progress in reducing smog depends largely upon reductions of NOx, or "oxides of nitrogen," which are considered "major contributors to smog formation and acid deposition." (17 C.C.R., § 93118(d)(19).) NOx contributes to the formation of ground-level ozone (smog) in the San Joaquin Valley, particularly during the summer months. (*Calif. Building Indus. Ass'n v. San Joaquin Valley Air Pollution Control Dist.* (2009) 178 Cal.App.4th 120, 126 ["*CBIA*"].) The San Joaquin Valley air basin does not meet the federal ozone standard required under the Clean Air Act; the area has thus been designated by EPA as "extreme non-attainment" for ozone under the federal National Ambient Air Quality standards ("NAAQs"). (75 Fed. Reg. 24409.)

1. The EA Fails to Analyze or Discuss Criteria Pollutants Other than <u>NOx</u>

The EA contains only a minimal discussion of impacts associated with criteria pollutants. (See EA at 51-52.) The EA only quantifies the emissions associated with one criteria pollutant: NOx. There is no discussion of other criteria pollutants, including particulate matter (PM), volatile organic compounds (VOCs), and reactive organic gases (ROG).

Whether CARB believes these impacts are insignificant is irrelevant. CEQA places the burden of environmental investigation on government rather than the public," and a lead agency "should not be allowed to hide behind its own failure to gather data." (See, e.g., *Sundstrom v. County of Mendocino* (1988) 202 Cal.App.3d 296, 311.) By failing to analyze the impacts of the proposed "re-adopted" LCFS regulation and the ADF regulation on criteria pollutants, other than NOx, the EA does not comply with CEQA.

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[2] San Joaquin Valley Air Pollution Control Dist., Guide for Assessing and Mitigating Air Quality Impacts (1998; Jan. 2002 rev.) § 4, Table 4-1, p. 26 (the "SJVAPD Guide"), *available at* http://www.valleyair.org/transportation/CEQA%20Rules/GAMAQI%20Jan%202002%20Rev.pdf

2. The Project Will have Significant Impacts Associated With NOx Emissions, Even Using CARB's Own Analyses

Although the EA estimates that NOx emissions will decrease over time, CARB itself estimates that increased use of biodiesel associated with the ADF regulation and the "re-adopted" LCFS regulation will result in additional NOx emissions of 1.29 tons per day [or 470.85 tons per year] in 2015. (ADF ISOR, Table B-1.) Although CARB's estimated increases in NOx are inaccurate, and drastically understate NOx emissions, as explained *infra*, an increase in NOx emissions of 470.85 tons per year is in itself significant, and CARB cannot plausibly claim the Projects' impacts will have "beneficial" impacts on operational criteria pollutant emissions.

Any attempt by the EA to offset, or mitigate, biodiesel NOx emissions with the use of renewable diesel fuel is erroneous. There is "nothing in either the proposed ADF regulation or the proposed LCFS regulation that mandates the use of any volume of biodiesel in California, much less the use of the exact ratio of renewable diesel to biodiesel assumed by CARB staff in its emissions analysis." (Decl. Lyons, at D-4.) Despite this, the EA does not include any analysis of the possibility that renewable diesels will not displace biodiesels at the rate contemplated in the ISOR. Thus, any alleged off-set is speculative, and does not excuse CARB's failure to analyze NOx increases associated with biodiesel, or to mitigate the 470.85 tons per year in emissions increased use of biodiesel will generate.

Moreover, none of the documents made available for public review by CARB (including the EA, the two ISORs, or the supporting materials) support staff's assertion "that 40% of renewable diesel used in California will be used by refiners to aid in compliance with CARB's existing diesel fuel regulations and that 60% will be blended downstream of refineries." (*Id.*) Indeed, this result defies common sense; to the extent fuel producers choose to blend renewable diesel in California, it would be far more logical for "them to do so by purchasing renewable diesel for use at their refineries where they can benefit from the other desirable properties of this fuel beyond its low carbon intensity (CI) value (e.g., high cetane number and fungibility with diesel fuel at all blend levels)," as opposed to "purchasing LCFS credits generated by downstream blenders of renewable diesel fuel." (*Id.*)

The Regulations will have significant impacts resulting from the emission of NOx caused by increase biodiesel usage. As a result, the EA's finding that the Regulations would have a "beneficial" effect to criteria pollutant emissions is erroneous, and not supported by substantial evidence.

3. The Analysis of NOx Impacts Is Flawed and Incomplete, and Omits Known Sources of Emissions

The EA's analysis significantly understates the true impacts associated with operational NOx emissions. CARB staff's calculation of NOx emissions associated with increased biodiesel usage was based on the erroneous assumption that biodiesel use in "New Technology Diesel Engines" (NTDEs) at levels up to B20 will not increase NOx emissions. As explained in the Declaration of James M. Lyons, the available data demonstrate "not only that NOx emissions from NTDEs will increase with the use of biodiesel in proportion to the amount of biodiesel present in the blend, but also that the magnitude of the increase on a percentage basis will be much greater than that observed for 'legacy vehicles.'" (Decl. Lyons, at D-4.)

Specifically, "if one simply and extremely conservatively assumes that NTDE NOx increases will be the same on a percentage basis as legacy vehicles and eliminates the NOx offsets assumed from renewable diesel, the NOx increases expected from biodiesel increase from 1.36 tons per day statewide in 2014 to approximately 3.44 tons per day—a factor of about 2.65." (Decl. Lyons, at D-4; see also ADF ISOR, Table B-1.) "For 2023, estimated NOx emission increases due to biodiesel rise to about 0.87 tons per day . . . ." (*Id.* at D-4, D-5.) Thus, accounting for NOx emissions associated with NTDEs alone, projected NOx emissions are far greater than those calculated by CARB staff.

By performing a detailed and comprehensive – yet conservative – analysis of NOx increases using generally accepted techniques, Sierra Research has concluded that NOx emissions are far more severe, and could total as much as 9.73 tons per day statewide in 2020, and 2.39 tons per day (or 872.35 tons per year) in 2020 in the San Joaquin Valley air basin alone. (Decl. Lyons at D-10 [Figure 1c], D-18 [Table 8].) This figure is vastly higher than the 10 tons per year threshold of significant adopted by the San Joaquin Valley Air Pollution Control District for projects under CEQA. (See SJVAPD Guide, § 4, Table 4-1, p. 26.)

4. The EA Fails to Quantify Impacts Associated With the Construction <u>Of New Facilities</u>

The EA posits that the Regulations would result in the construction of new or modified fuel production facilities to meet demand for fuels created by the Regulations, including processing plants for agriculture-based ethanol, cellulosic ethanol, and biomethane. Without quantifying the potential impacts of these facilities, the EA makes the bare conclusion that several of the impacts associated with these facilities would be "significant and unavoidable."

An environmental document, including a functional equivalent document, however, cannot simply label an impact "significant and unavoidable" without first providing a discussion and analysis. Such a backwards approach "allows the agency to travel the legally impermissible easy road to CEQA compliance." (*Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs* (2001) 91 Cal.App.4th 1344, 1370.) Rather, the lead agency must quantify the impact, and consider feasible mitigation based on that analysis. (See, e.g., *Sundstrom*, *supra*, 202 Cal.App.3d at 311 ["CEQA places the burden of environmental investigation on government rather than the public," and a lead agency "should not be allowed to hide behind its own failure to gather data."].)

The potential impacts associated with the development of new or modified facilities *can* be quantified. As explained in the Declaration of James M. Lyons, CARB attempted to quantify emissions from such facilities in its 2009 rulemaking. (Decl. Lyons at B-3.)

Moreover, by declining to quantify impacts associated with new facilities, the EA essentially forecloses any and all mitigation measures. For example, if potential criteria pollutant emissions were quantified, CARB could modify the proposed regulation, enact another regulation, or otherwise develop mitigation to reduce such impacts. CARB could also reconfigure the Regulations, create performance standards for new California biodiesel facilities, or otherwise create disincentives to develop new facilities within California. Instead, however, the EA merely provides a laundry list of *potential* mitigation measures, without actually requiring that those mitigation measures be implemented, or analyzing whether those mitigation measures would reduce the impacts to a less-than-significant level.

5. The Increased NOx Emissions Under the Regulations Violate AB32

NOx emissions caused by the Regulations also violate AB 32. Health and Safety Code Section 38570, subdivision (b), requires CARB, "***[p]rior to*** the inclusion of any market-based compliance mechanism in the regulations," to "(1) [c]onsider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution," and "(2) [d]esign any market-based compliance mechanism *to* ***prevent any increase*** in the emissions of toxic air contaminants or criteria air pollutants." (Health & Saf. Code § 38570, subd. (b) [emphasis added]. In addition, for any regulation adopted under AB32 like the LCFS regulation, the Board must "***ensure*** . . . activities undertaken pursuant to the regulations do not interfere with . . . efforts to achieve and maintain federal and state ambient air quality standards" (*Id.* § 38562(b)(4); emphasis added)].) Because the Regulations would ***increase*** NOx emissions from biodiesel, the Regulations are unlawful.

C. The Mitigation Measures Proposed in the EA Inadequate Under CEQA

The Mitigation Measures specified in the EA are also inadequate under CEQA. The EA finds that several potential impacts of the Regulations would be "significant and unavoidable," resulting from the construction of new or modified facilities to meet demand for fuels created by the Regulations, including processing plants for agriculture-based ethanol, cellulosic ethanol, and biomethane. Rather than including enforceable mitigation, however, the EA merely sets forth "recognized practices" that are "routinely required" to avoid or minimize impacts, without requiring the implementation of any specific measure, or even evaluating whether any such measures – if incorporated – would actually reduce or minimize the impact. This is improper under CEQA for several reasons.

First, mitigation must be enforceable. (Pub. Resources Code, § 21081.6, subd. (b); CEQA Guidelines, § 15126.4(a)(2).) The EA, however, does not require any particular measure. Rather, the EA just sets forth a potential mitigation measures that local land use authorities *could* implement if they choose to do so. Because none of the mitigation measures identified in the EA are enforceable, they are inadequate under CEQA.

Mitigation must also be effective, and an agency must identify mitigation measures that will minimize the project's significant impacts by reducing or avoiding them. (See, e.g., Pub. Resources Code, §§ 21001, 21100.) The EA, however, does not discuss *how* any of the proposed mitigation measures – if implemented – would reduce or avoid the potential impacts of the Regulation, and if so, to what degree.

Nor may CARB permissibly defer the formulation of specific mitigation. To defer mitigation, a lead agency must still (1) "evaluate[] the potentially significant impacts of the project," (2) "identif[y] measures that will mitigate those impacts," (3) "commit[] to the mitigating the significant impacts of the project," and (4) "specify performance standards which would mitigate the significant effect of the project" to govern the subsequent mitigation. (*California Native Plant Soc'y v. City of Rancho Cordova* (2009) 172 Cal.App.4th 603, 621.) Here, in contrast, the EA does not specifically identify the potential impacts, require the mitigation of significant impacts, or "specify performance standards which would mitigate the significant effect of the" Regulations. (See *id.*)

As a result, CARB must revise the EA to further analyze potential mitigation measures, and include enforceable mitigation to minimize the recognized potentially significant impacts of the Regulations, and recirculate the revised EA for public review.

D. <u>The EA Fails to Analyze Impacts Associated With Fuel Shuffling</u>

Since its enactment in 2009, the LCFS regulation has led to a phenomenon called "fuel shuffling," in which lower-CI fuels are shipped from around the world to California and higher-CI fuels must be sent for sale elsewhere. (Decl. Lyons at B-4.) CARB has admitted that fuel shuffling will occur. (See, e.g., December 2009, Final Statement of Reasons at 241.) There is no environmental advantage to fuel shuffling, for the same fuels are still produced and consumed, and the same GHGs are still emitted from those processes. Rather, because the LCFS regulation encourages the shipment of fuels to alternative locations that are further from origin facilities, fuel shuffling actually causes emissions of GHGs to increase.[3]

These increases in emissions are potentially significant, but discussed nowhere in the EA. For example, even using CARB's direct emissions model (GREET), GHG emissions associated with shuffling would be significant. For example, the LCFS regulation will likely result in higher amounts of Brazilian cane ethanol being shipped to California, with more traditional fuels being shipped from California to Brazil and other destinations by ship. Additional shipping corn- and sugarcane-based ethanol by ship to and from destinations such as Brazil alone would result in an additional 150,000 tons per year of CO2 equivalent emissions. (Appendix G) Using more accurate direct emission models, increase CO2 equivalent emissions would be between 385,000-735,000 tons per year – or nearly 4.5% of the total emissions benefits CARB assets the Regulations would allegedly cause. (Appendix G) Notably, these figures do not include increases in emissions associated with fuel shuffling of crude oils, or the increases in the transport of ethanol by rail as part of fuel shuffling. (Appendix G)

The EA likewise does not evaluate whether fuel shuffling caused by the Regulations would result in additional increases in criteria pollutant emissions. Because transportation of fuels by rail, truck, and sea indisputably create emissions of criteria pollutants, both inside and outside[4] California, the EA must analyze those potential impacts to determine

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[3] Because the LCFS regulation will not achieve any benefits as to climate change, CARB cannot base any statement of overriding considerations on this assertion.

[4] CARB must analyze both in-state and out-of-state impacts caused by the Regulation. CEQA defines "environment" to include "the physical conditions that exist within the area which will be affected by a proposed project, including land, air, water, minerals, flora, fauna, noise, or objects of historic or aesthetic significance." (Public Resources Code, § 21060.5.) That definition includes no geographic limitation. We also understand CARB has considered out-of-state impacts in previous rulemakings.

whether they are significant. (See, e.g., *Sundstrom*, *supra*, 202 Cal.App.3d at 311 ["CEQA places the burden of environmental investigation on government rather than the public," and a lead agency "should not be allowed to hide behind its own failure to gather data."].)

Thus, to accurately identify and analyze the impacts of the Regulations, the EA must be revised to address impacts associated with fuel shuffling, and recirculate the EA for public review.

E. The EA's Discussion of the Growth Energy Alternative Is Insufficient

The requirement that environmental documents identify and discuss alternatives to the project stems from the fundamental statutory policy that public agencies should require the implementation of feasible alternatives or mitigation measures to reduce the project's significant impacts. (See, e.g., Pub. Resources Code, § 21002.) The lead agency must focus on alternatives that can avoid or substantially lessen a project's significant environmental effects. (See *id.*) The EA here impermissibly rejects discussion of the Growth Energy Alternative, and does not include any discussion of a Cap and Trade Alternative. These alternatives are discussed in greater detail below. The CEQA Guidelines specifically recognize that comments raised by members of the public on an environmental document are particularly helpful if they suggest "additional specific alternatives . . . that would provide better ways to avoid or mitigate the significant environmental effects." (CEQA Guidelines, § 15204.)

The Growth Energy Alterative contemplates an adjustment to the cap and trade regulation in Title 17 of the California Code of Regulations to account for whatever increment of GHG emissions reductions would be foregone by eliminating the LCFS regulation. CARB concedes the Growth Energy Alternative would achieve the same emissions reductions contemplated under the Regulations. (See Standardized Regulatory Impact Assessment at 26-27.)

The Growth Energy Alternative also would not result in fuel shuffling, or the construction of numerous fuel production plants in California. (See Decl. Lyons at B-4.) Because the only impacts found to be "significant and unavoidable" under the EA result from the construction of new and modified fuel production facilities, the Growth Energy Alternative would likely eliminate ***all*** of the Regulations' significant and unavoidable impacts. Because the Growth Energy Alternative would lessen the "significant and unavoidable" effects of the Regulations, it should be included as an alternative in a recirculated EA. (Pub. Resources Code, § 21002.)

Despite these benefits, the EA rejects the Growth Energy Alternative to the Regulations because it would allegedly require that actions be taken to mitigate increased NOx emissions from biodiesel under circumstances where CARB staff incorrectly assumed there would be no increased emissions due to biodiesel use under the ADF. These assumptions are flawed.

As demonstrated by Sierra Research, the ADF regulation will result in significant and unmitigated increases in NOx emissions throughout California, including significant impacts within the San Joaquin Valley and South Coast air basins. (Decl. Lyons ¶ 15.) The EA concedes the mitigation proposed under the Growth Energy Alternative would require "mitigation in exactly those areas where CARB staff was lead to believe it was not required based on its flawed emissions analysis." (Decl. Lyons at G-3.) Because of this, and the fact that the Growth Energy Alternative expands the conditions under which this mitigation has to be applied in order to eliminate the potential for any increase in NOx emissions due to biodiesel use, the Growth Energy Alternative is environmentally superior to the ADF regulation. (*Id.*)

To the extent CARB argues the Growth Energy Alternative does not meet the objective of "greater innovation and development of cleaner fuels," this is not a valid reason to reject discussion of the alternative. First, as explained in the Declaration of James M. Lyons, the Growth Energy Alternative would also foster greater innovation and development of cleaner fuels in California because most of the same fuels will be blended into California fuels as a result of the federal RFS program. (Decl. Lyons at C-4.)

But even if the Growth Energy Alternative would not meet this project objective, (see ISOR at E-40, E-41), CARB may not simply reject discussion of an alternative simply because it does not meet one of several project objectives. Rather, a feasible alternative that would substantially reduce the project's significant impacts should not be excluded from the analysis simply because it would not fully achieve the project's objectives. (See *Habitat & Watershed Caretakers v. City of Santa Cruz* (2013) 213 Cal.App.4th 1277, 1304.) Here, as discussed above, the Growth Energy Alternative would essentially eliminate all of the "significant and unavoidable" impacts of the Regulations.

Further, to the extent CARB relies upon this objective to reject mere analysis of the Growth Energy Alternative, this is improper because it would essentially limit the range of alternatives described to regulations that are nearly identical to the Regulations. Because agencies may not "give a project's purpose an artificially narrow definition," (*In re Bay-Delta Programmatic Envt'l Report Coordinated Proceedings* (2008) 43 Cal.4th 1143, 1166), and CARB has previously demonstrated a pattern of prejudging the LCFS regulation prior to completing the environmental review process, (see *POET, LLC v. California Air Resources Board* (2013) 218 Cal.App.4th 681), CARB should not artificially tailor its objectives to limit the range of alternatives to the LCFS regulation itself.

In short, the Growth Energy Alternative better achieves the project objectives than the Regulations, and is environmentally superior to the Regulations. As a result, the EA must analyze the Growth Energy Alternative, and CARB must recirculate the EA for public comment.

F. CARB Must Substantially Revise the LCFS Regulation, the ADF Regulation, And the EA, Due to Material Inconsistencies Between the Two Regulations

As explained in detail in the Declaration of James M. Lyons, the LCFS regulation and the ADF regulation "contain inconsistent and conflicting definitions," and lack "provisions requiring the determination, through testing, of the biodiesel content of commercial blendstocks." (Decl. Lyons ¶ 17.) These inconsistencies include that: (1) the Regulations contain different definitions for the term "biodiesel"; (2) the term "Biodiesel Blend" under the LCFS regulations contains at least 6% biodiesel, while a "Biodiesel Blend" under the ADF is a diesel fuel containing any biodiesel; (3) the LCFS regulation defines "Diesel Fuel Blend" as a blend of diesel fuel and up to 5% biodiesel, while such a fuel would be considered "CARB diesel" under the ADF regulation; and (4) under the proposed ADF regulation, "B20" is nonsensically defined as a fuel that contains between 6% and 20% biodiesel, which directly contradicts the definition of "Blend Level" in same regulation. (See Decl. Lyon at H-3, H-4.)

In addition, the term "Biodiesel Blend" is defined in the ADF regulation as a mixture of biodiesel and an undefined fuel referred to as "petroleum-based CARB diesel." "Blend Level" applies to blends of all fuels subject to the ADF regulation, including biodiesel, and is defined as the ratio of an "Alternative diesel fuel" mixed with "CARB diesel." As noted above, however, "CARB diesel" may already contain as much as 5% biodiesel under the proposed ADF regulation. The addition of biodiesel to a fuel already containing some amount of biodiesel up to 5% will cause the actual biodiesel content to be higher than the blender expects, which in turn will result in increased NOx emissions. (See Decl. Lyons at F-3, F-4.) These potential NOx emissions are not discussed in the EA.

The internal inconsistencies between the LCFS regulation and the ADF regulation also render the project description defective. "An accurate, stable and finite project description is the sine qua non of an informative and legally sufficient EIR." (*County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 193.) Because the LCFS regulation and the ADF regulation contain material, conflicting terms, the project description is not accurate or stable, and must be revised.

Due to these material inconsistencies, the EA is legally flawed. Both the proposed regulations and the EA must be revised significantly, and recirculated for public review.

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FRESNO SUPERIOR COURT
By________ DEPT. 402 - DEPUTY

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SUPERIOR COURT OF CALIFORNIA, COUNTY OF FRESNO

CENTRAL DIVISION

POET, LLC and JAMES M. LYONS Petitioners and Plaintiffs, vs. CALIFORNIA AIR RESOURCES BOARD; JAMES N. GOLDSTENE, in his official capacity as Executive Officer of the California Air Resources Board; LORI ANDREONI, in her official capacity as a Manager of the California Air Resources Board; and ELLEN PETER, in her official capacity as Chief Counsel of the California Air Resources Board, Respondents and Defendants.	Case No. 09 CE CG 04659 **[redacted] PEREMPTORY WRIT OF MANDATE** Department: 402 Honorable Jeffrey Y. Hamilton, Jr. Action Filed: December 23, 2009

Judgment having been entered in this proceeding, ordering that a peremptory writ of mandate be issued from this Court,

IT IS ORDERED that, immediately on service of this writ:

1. Respondent and Defendant California Air Resources Board ("ARB") set aside its approval of the Low-Carbon Fuel Standard ("LCFS") regulations, including Board Resolution 09-31, dated April 23, 2009; Executive Order R-09-014, dated November 25, 2009; Executive Order R-10-003, dated March 4, 2013; and ARB's decision to defer the formulation of mitigation measures relating to NOx emission from biodiesel.

2. ARB shall (a) select a decision maker, (b) take such action as may be necessary to assure that the decision maker has full authority to approve or disapprove the proposed LCFS regulations and to complete the environmental review, and (c) take such action as may be necessary to assure the decision maker does not approve the proposed LCFS regulations until after the decision maker has completed the environmental review.

3. ARB shall address whether the project will have a significant adverse effect on the environment as a result of increased NOx emissions, make findings (supported by substantial evidence) regarding the potential adverse environmental effect of increased NOx emissions, and adopt mitigation measures in the event the environmental effects are found to be significant.

4. ARB shall allow public comments for a period of at least 45 days on all issues related to the approval of the proposed LCFS regulations (which shall include, without limitation, issues concerning (a) the carbon intensity values attributed to land use changes, (b) the application of the GTAP model, and (c) any new material in any supplemental staff report prepared in connection with the proposed LCFS regulations) and respond to those comments before approving the proposed LCFS regulations.

5. ARB shall [redacted] include in its rulemaking file [redacted] the four emails referenced in the July 15, 2013, Opinion of the Fifth District Court of Appeal, case number F064045, at pages 61 through 80.

6. ARB shall preserve the status quo by continuing to adhere to the LCFS regulations standards in effect for 2013 until the corrective action is completed. Notwithstanding the directive herein that ARB set aside its prior approvals of the LCFS regulations and related resolutions and orders, the LCFS regulations shall remain in operation and shall be enforceable unless its operation is suspended as provided below.

7. Pursuant to Public Resources Code Section 21168.9(c), the Court does not direct ARB to exercise its lawful discretion in any particular way.

8. Pursuant to Public Resources Code Section 21168.9(c), the Court shall retain jurisdiction over ARB's proceedings by way of a return to this peremptory writ of mandate until the Court has determined that ARB has fully complied with the provisions of CEQA.

9. ARB shall file an initial return no later than 30 days after issuance of this writ. The initial return shall explain what action ARB will take to satisfy the writ's requirements; this explanation shall include a schedule and shall identify who will act as the decision maker.

10. Within 15 days of the filing of the initial return, Plaintiffs POET, LLC, and James M. Lyons ("Plaintiffs") may file a response, which shall include Plaintiffs' objections to matter addressed in the initial return. If Plaintiffs file a response, ARB's reply shall be due no later than 15 days after the response.

11. ARB shall proceed in good faith without delay. In the event ARB fails to proceed in good faith with diligence, this Court immediately shall vacate Paragraph 6 of this writ, which preserves the status quo, and shall direct ARB to set aside the LCFS regulations (i.e., suspend the operation and enforcement of the regulations).

IT IS SO ORDERED.

DATED: 2/10/14

Honorable Jeffrey Y. Hamilton, Jr.
Judge of the Superior Court

Submitted on this 23rd day of December 2013, by:

Timothy Jones
John P. Kinsey
Daren A. Stemwedel
Attorneys for Petitioners and Plaintiffs
POET, LLC and James M. Lyons

PROOF OF SERVICE

My business address is 265 E. River Park Circle, Suite 310, Post Office Box 28340, Fresno, California 93720. I am employed in Fresno County, California. I am over the age of 18 years and am not a party to this case.

On the date indicated below, I served the foregoing document(s) described as **[PROPOSED] PEREMPTORY WRIT OF MANDATE** on all interested parties in this action by placing a true copy thereof enclosed in sealed envelopes addressed as follows:

SEE ATTACHED SERVICE LIST

_____ **(BY MAIL)** I am readily familiar with the business' practice for collection and processing of correspondence for mailing, and that correspondence, with postage thereon fully prepaid, will be deposited with the United States Postal Service on the date noted below in the ordinary course of business, at Fresno, California.

_____ (BY PERSONAL SERVICE) I caused delivery of such envelope(s), by hand, to the office(s) of the addressee(s).

_____ (BY ELECTRONIC MAIL) I caused such documents to be scanned into PDF format and sent via electronic mail to the electronic mail addressee(s) of the addressee(s) designated.

_____ (BY FACSIMILE) I caused the above-referenced document to be delivered by facsimile to the facsimile number(s) of the addressee(s).

X (BY OVERNIGHT COURIER) I caused the above-referenced envelope(s) to be delivered to an overnight courier service for delivery to the addressee(s).

EXECUTED ON December 23, 2013, at Fresno, California.

X **(STATE)** I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Lisa Turri Zanoni

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SUPERIOR COURT OF CALIFORNIA • COUNTY OF FRESNO Civil Department - Non-Limited 1130 "O" Street Fresno, CA 93724-0002 (559)457-1900	FOR COURT USE ONLY
TITLE OF CASE: **Poet, LLC vs California Air Resources Board/CEQA**	
CLERK'S CERTIFICATE OF MAILING	CASE NUMBER: **09CECG04659 JH**

Name and address of person served:

Timothy Jones
Wanger Jones Helsley PC
P.O. Box 28340
Fresno, CA 93729

CLERK'S CERTIFICATE OF MAILING

I certify that I am not a party to this cause and that a true copy of the 02/10/2014 Peremptory Writ of Mandate was mailed first class, postage fully prepaid, in a sealed envelope addressed as shown below, and that the notice was mailed at Fresno, California, on:

Date: **2/10/2014** Clerk, by M. Santana, Deputy

M. Santana

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