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September 23, 2015

Via Electronic Mail, Overnight Mail & Hand Delivery

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 Clerk:

I am submitting the following comments on behalf of Growth Energy, related to the California Air Resources Board's ("ARB") September 24-25, 2015, hearing on the Proposed Amendments to the California Low-Carbon Fuel Standards Regulation (the "LCFS regulation") and the Proposed Regulation of the Commercialization of Alternative Diesel Fuels (the "ADF regulation"). The LFCS regulation and the ADF regulation are collectively referred to herein as the "Regulations."

Growth Energy requests that ARB decline to adopt the Regulations. As explained previously, there are numerous open issues, uncertainties, inconsistencies and procedural errors that have marked this regulatory process. ARB may not, under CEQA, the APA, and its own certified regulatory program, take action on the Regulations, as currently proposed. Instead, ARB Staff should work with stakeholders to craft a better regulation; seriously consider alternatives that would avoid the recognized "significant and unavoidable" effects of the Regulations; and analyze all fuels in a consistent and fair manner.

In addition to these comments, I have enclosed the Declaration of James C. Lyons, which is enclosed as **Attachment "A."**

A. The EA Should Be Revised to Employ a Baseline that Analyzes the Project as a Whole, and Recognizes that Environmental Review of the Regulations Commenced Well Before 2014

ARB has never performed a legally valid environmental review of the original LCFS regulation. Rather, in *POET, LLC v. California Air Resources Board* (2013) 218 Cal.App.4th 681 ("*POET*"), the Court of Appeal found that ARB 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.

Now, rather than evaluating the effects of the original LCFS regulation that is presently being enforced, ARB – through a regulatory slight-of-hand apparently designed to artificially limit environmental review – is apparently seeking to "re-adopt" the LCFS regulation.

First, regardless of whether ARB characterizes its action as "modifying" or "re-adopting" the LCFS regulation,[1] the fact remains that ARB must consider the ***whole of the project***, and the environmental review of the LCFS regulation commenced in 2009. Instead, ARB here has attempted to analyze only those impacts associated with the *modified* LCFS regulation.

"CEQA forbids 'piecemeal' review of the significant environmental impacts of a project." (*Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs* (2011) 91 Cal.App.4th 1344, 1358, as modified on denial of reh'g (Sept. 26, 2001).) The Public Resources Code, section 21002.1, subd. (d) requires the lead agency to "consider[ ] the effects, both individual and ***collective***, of all activities involved in [the] project." [emphasis added.] Further, a project for CEQA purposes means "the whole of an action." (Code Regs. tit. 14, § 15378.) Thus, to comply with the writ in *POET*, to avoid piecemealing, and to accurately apprise the public and the decisionmakers of the potentially significant effects of the LCFS regulation and the ADF regulation, ARB must analyze the effects of the ***entire*** project – not just the "re-adopted" regulation.

Growth Energy's prior comments also argued that, by failing to analyze the original regulation's impacts, ARB is using an inaccurate environmental baseline for its review of the regulations.

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[1] Based on the agenda released by ARB Staff, ARB is not seeking to rescind the existing regulation.

In addition to these concerns, documents released by ARB have revealed that ARB is using a pre-LCFS baseline (*i.e.*, 2009/2010) for *some* favored fuels, but using a 2014 baseline for others. Specifically, as explained in the Lyons Declaration, ARB will be proving LCFS credits for electric forklifts and fixed guideway systems "despite the fact that electricity was already being used as a fuel for these applications in 2010," and that there will be "no increase in the use of electricity relative to 2010 levels to occur as a result of the LCFS regulation." (Decl. Lyons ¶ 15.) In other words, ARB's baseline *presumes* electric forklifts and fixed guideway systems presently do not exist, even though that is obviously not the case.

ARB treats Midwest corn ethanol differently. Specifically, ARB's analysis recognizes that corn ethanol "was being added to gasoline in California in 2010," and includes present use of corn ethanol in its environmental and regulatory baseline.

Based on the foregoing, ARB has failed to use consistent baselines across the spectrum for fuels regulated under the regulations. ARB cannot assert that it should not be required to use a pre-regulation (2009) baseline, while it is specifically using a baseline other than 2014 for some fuels, including electric forklifts and fixed guideway systems. In addition, it is unfair (and internally inconsistent) to analyze fuels such as corn ethanol using 2014 levels, while applying different standards for others.[2]

ARB Staff has also asserted a baseline using the date upon which the environmental review commenced (2009) would not "yield meaningful information for environmental analysis." (Responses to Comments at 2-352.) This is inaccurate, however, as it is possible to determine the amount of unmitigated NOx emissions were generated by the original LCFS regulation – which ARB previously conceded was significant – and determine how to mitigate those impacts. (See, e.g., *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1204.)

Thus, as explained previously, (i) ARB's baseline for environmental review is unclear, and shifts based on the type of fuel being analyzed, (ii) ARB has impermissibly ignored pre-2014 impacts, contrary to both the writ issued in *POET*, CEQA, and common sense; (iii) ARB has failed to include analysis of impacts associated with the original regulation (which has never undergone valid CEQA review), under a cumulative impacts analysis or otherwise; (iv) ARB has impermissibly piecemealed/segmented environmental review; and (v) the project description is unstable and thus inadequate under CEQA.

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[2] ARB also appears to have analyzed at least one alternative using a different baseline than the LCFS regulation. Specifically, one alternative is the Gasoline-Only Compliance Curve Alternative, which ARB asserts "would achieve a 10 percent reduction in CI by 2020 from a 2010 baseline for gasoline and gasoline substitute fuels only." By focusing on 2010 as the baseline year for the Gasoline-Only Compliance Curve Alternative, and 2014 as the baseline for the LCFS regulation and the ADF regulation, ARB is not analyzing the environmental effects of the alternatives in an internally consistent manner.

B. Because the Growth Energy Alternative Is Feasible, and Would Eliminate the "Significant and Unavoidable" Effects of the Regulations, ARB Cannot Adopt the Regulations as Proposed

Growth Energy has previously commented that ARB's discussion of the Growth Energy Alternative to the ADF regulation is insufficient. Specifically, although the Growth Energy Alternative would cause the potentially significant impacts identified in the EA, and would also not result in fuel shuffling, ARB has rejected the alternative.

ARB Staff asserts they rejected the Growth Energy alternative because (i) it purportedly does not meet the objective of "greater innovation and development of cleaner fuels," and (ii) it allegedly "would not reduce any potentially significant environmental effects, and that although the alternative may accelerate the timeframe of emissions benefits compared to the proposed ADF Regulation it would do so at an unreasonable cost, in a way that may not be technically feasible, and would be unnecessarily strict." (Responses to Comments 2-392.)

These assertions are erroneous, and not supported by substantial evidence in the record. As explained in Growth Energy's February 17, 2015, comments, there is no evidence in the record to suggest the Growth Energy Alternative would not spur "innovation and development of cleaner fuels"; rather, James M. Lyons stated in his February 17, 2015, declaration that the Growth Energy Alternative would have such an effect. Further, 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.)

ARB's assertion that the Growth Energy Alternative "would not reduce any potentially significant environmental effects" is erroneous, and belied by ARB's own environmental document. ARB concedes the Growth Energy Alternative would have environmental benefits, as it "may accelerate the timeframe of emissions benefits compared to the proposed ADF Regulation." (Responses to Comments 2-392.) Further, the EA finds that impacts associated with the construction of new and modified fuel production facilities would be "significant and unavoidable." Because the Growth Energy Alternative does not contemplate the construction of new and modified fuel production facilities, the Growth Energy Alternative, ***would entirely avoid the potentially significant effects described in the EA.***

In any event, ARB presents no evidence to suggest the Growth Energy Alternative "would not reduce any potentially significant environmental effects." CEQA, however, provides that an agency may not rely on an unanalyzed theory that an alternative might not be environmentally superior to the project; rather, to reject an alternative, the agency must provide facts and analysis to support such a conclusion. (*Habitat & Watershed Caretakers v. City of Santa Cruz* (2013) 213 Cal.App.4th 1277, 1305; *Kings County Farm Bureau v. City of*

Hanford (1990) 221 Cal.App.3d 692, 737.) Because ARB has provided no such facts, it cannot lawfully adopt the regulations without analyzing and considering the Growth Energy Alternative.

ARB also asserts, without evidence, that the Growth Energy Alternative would impose "unreasonable cost[s]," and "***may*** not be technically feasible." (*Id.* [emphasis added].) First, these statements are insufficient for ARB to argue the Growth Energy Alternative is not feasible, as (i) ARB staff merely asserts the costs would be potentially "unreasonable,"[3] and "infeasible," and (ii) ARB staff merely asserts that the Growth Energy "may" not be technically feasible, without explaining why that "may" be the case.

But even if ARB were asserting the Growth Energy Alternative were not "feasible," CEQA plainly provides that findings of "infeasibility" sufficient to reject an alternative – where, as here, there are significant and unavoidable impacts – must be supported by relevant economic evidence. (See *Uphold Our Heritage v. Town of Woodside* (2007) 147 Cal.App.4th 587, 601.) Here, ARB has proffered no evidence the Growth Energy Alternative would be "infeasible" in any respect.

ARB cannot ignore the Growth Energy Alternative. ARB's own certified regulatory program provides that "[a]ny action or proposal for which significant adverse environmental impacts have been identified during the review process shall not be approved or adopted as proposed if there are . . . feasible alternatives available which would substantially reduce such adverse impact." (17 Cal. Code Regs., § 60006.) Here, the regulations would result in "significant and unavoidable" environmental effects, that would be eliminated entirely by the Growth Energy Alternative. ARB Staff admits the Growth Energy Alternative would actually "***accelerate*** the timeframe of emissions benefits compared to the proposed ADF Regulation." (Responses to Comments 2-392 [emphasis added].) ARB Staff therefore cannot argue the Growth Energy Alternative supposedly would not be "accomplished in a successful manner within a reasonable period of time," nor can ARB Staff argue the Growth Energy Alternative is somehow inconsistent "with the state board's legislatively mandated responsibilities and duties." (17 Cal. Code Regs., § 60006.) As a result, pursuant to Section 60006, ARB cannot approve the regulations as drafted, and must instead consider the Growth Energy Alternative.

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[3] Notably, while ARB Staff on the one hand argues the Growth Energy Alternative would result in "unreasonable costs," the regulations as drafted could essentially drive U.S. Midwestern corn ethanol out of the California market in exchange for cane ethanol from Brazil within a few years. Because ARB has presented no evidence to back-up their assertions with respect to the rejection of the Growth Energy Alternative, it is unclear why the economic costs in one context are "unreasonable," but supposedly "reasonable" in another. This is particularly true in light of Growth Energy's concerns regarding the SRIA and ARB's economic analysis, which are equally flawed.

ARB also cannot approve the regulations as currently proposed because (i) the Growth Energy Alternative was wrongfully omitted from the EA, (ii) ARB lacks substantial evidence to support its decision not to include the Growth Energy Alternative in the EA, (iii) the EA does not include a reasonable range of alternatives (as it, *inter alia*, omits the Growth Energy Alternative, or any other meaningful alternative), and (iv) ARB cannot find overriding considerations justify the adoption of the regulations despite the admittedly significant impacts that would be avoided by the implementation of the Growth Energy Alternative.

C. The Rulemaking File Includes No Evidence, Analysis, or Technical Basis for the Relaxation of NOx Control Levels Resulting from the "Grand Compromise" Between the Biodiesel Industry and CARB Staff

As explained in the accompanying declaration of James M. Lyons, the NOx Control Levels included in the final proposed ADF regulation are far less stringent than those proposed in the July 29, 2014, *Preliminary Rulemaking Proposal for Biodiesel Use as an Alternative Diesel Fuel*. (Decl. Lyons ¶¶ 6-7.) This appears to have been the result of a "great" or "grand" compromise between CARB and biodiesel interests. (See *id.*)

There are no documents in the rulemaking file regarding or reflecting the terms of any such "compromise," nor are there any communications between the biodiesel industry and CARB Staff relating to such negotiations. (*Id.*) Moreover, there is no evidence or other data in either the rulemaking file or the EA explaining why the NOx Control Levels were reduced so dramatically between July 2014 and February 2015, nor is there any technical basis to support the relaxation of the NOx Control Levels. (*Id.*)

Prior to its consideration of the Regulations for adoption, ARB should disclosure the terms of the compromise referenced by the commenting parties, and provide the technical basis to support the relaxation of the NOx Control Levels.

D. ARB Failed to Adequately Respond to Comments

ARB's certified regulatory program requires that ARB receive, summarize, and respond to comments received during the evaluation of the Regulations:

> If comments are received during the evaluation process which raise significant environmental issues associated with the proposed action, the staff shall 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.

(17 Cal. Code Regs., § 60007(b).) The same rules and guidelines for responses to comments apply to certified regulatory programs as a public agency considering an EIR. (*Ebbetts Pass, supra*, 123 Cal.App.4th at 1356-57; *Dunn-Edwards Corp. v. South Coast Air Quality Mgmt. Dist.* (1993) 19 Cal.App.4th 519, 533-34; *Gallegos v. State Bd. of Forestry* (1978) 76 Cal.App.3d 945, 954.)

Specifically, CEQA requires the public agency to "describe the disposition of each of the significant environmental issues raised and must particularly set forth in detail the reasons why the particular comments and objections were rejected and why the agency considered the development of the project to be of overriding importance." (*Ebbetts Pass, supra*, 123 Cal.App.4th at 1356-57 [citing *Gallegos, supra*, 76 Cal.App.3d at 954].) "The purpose of this requirement is to provide the public with a good faith, reasoned analysis why a specific comment or objection was not accepted." (*Environmental Protection Info. Ctr., Inc. v. Johnson* (1985) 170 Cal.App.3d 604, 628.) As such, the courts have held that "conclusory responses unsupported by empirical information, scientific authorities or explanatory information" are not sufficient "to satisfy the requirement of a meaningful, reasoned response: conclusory responses fail to crystallize issues, and afford no basis for a comparison of the problems caused by the project and the difficulties involved in the alternatives." (*Id.*) In other words, "[t]here must be good faith, reasoned analysis in their response. Conclusory statements unsupported by factual information will not suffice." (CEQA Guidelines, § 15088(c).)

Nearly all of ARB Staff's responses to Growth Energy's comments failed to meet these standards. Most of the responses merely reiterate ARB's analysis as presented in the ISOR, and provide no new evidence. For example, ARB Staff provides no additional facts or evidence in support of ARB's rejection of the Growth Energy Alternative.

Moreover, as explained in the Lyons Declaration, the responses to comments essentially ignore comments made by Growth Energy with respect to conventional diesel engines, including comments refuting ARB Staff's assertion that there is no data to establish a relationship between soy-blends below B5 and NOx in the 0-5 percent range. ARB Staff likewise does not address comments demonstrating that some animal blends will increase NOx, depending on how the biodiesel blending has changed the cetane number (CN) of the blended fuel itself. ARB Staff also did not address comments showing that ARB's own evidence suggests that animal feedstocks with lower CN will increase NOx.

ARB Staff also failed to adequately respond to comments regarding the NOx impacts associated with NTDEs. Rather, ARB's responses merely reiterate their prior conclusions. Others are non-responsive. For example, when commenting parties raised concern that ARB was relying on only two studies of NTDEs, ARB Staff merely responded that the author of the study was well-regarded, without discussing the data. Staff also did not respond to comments demonstrating the "use of biodiesel fuels in NTDEs may lead to the loss of NOx conversion efficiency in urea-SCR systems," instead merely asserting that it did not consider the concern or specifically examine the issue.

These are just a few of many examples of ARB's non-responsive comments. In short, ARB should decline to approve the Regulations until ARB has complied with its obligations under CEQA and Section 60007 of its certified regulatory program.

E. Submission of Update to "Appendix D" From Growth Energy's February 17, 2015, Comments on the Regulations

Growth Energy's February 17, 2015, comments on the regulations included a document entitled, *Appendix "D": Compliance with the Revised LCFS Program and Associated Economic Impacts*, which was prepared by Edgeworth Economics. As part of the instant comments, Edgeworth Economics has provided a revised Appendix "D" that includes current ethanol spot price information. A revised version of Appendix "D" is attached hereto as **Attachment "B."**

F. Submission of Administrative Record of Proceedings in *POET v. CARB*

It is unclear whether ARB is taking the position that ARB's previous rulemaking and environmental review of the LCFS regulation are relevant to ARB's consideration of the proposed "re-adoption" of the LCFS regulation in 2015. To ensure ARB's records from the original rulemaking are included in the rulemaking file, this letter encloses a CD including the administrative record of proceedings in the matter of *POET v. CARB*, Fresno County Superior Court, Case No. 09-CECG-04659.

G. Conclusion

In light of the foregoing issues, and the issues raised in Growth Energy's prior comments, ARB should decline to adopt the Regulations, and should instead (i) work with stakeholders to craft a better regulation; (ii) seriously consider alternatives (including the Growth Energy Alternative) that would avoid the recognized "significant and unavoidable" effects of the Regulations; and (iii) analyze all fuels in a consistent and fair manner.

Respectfully submitted,

John P. Kinsey

Enclosures

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

Attachment "A"

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 Exhibit 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 my further review of the documents published by CARB related to the Proposed Re-Adoption of the Low Carbon Fuel Standard Regulation (the LCFS Regulation) and to the Proposed Regulation on the Commercialization of Alternative Diesel Fuels (ADFs) in light of new information and facts that have developed since the February 19, 2015 Public Hearing. This includes the

Final Environmental Analysis (EA) and Response to Comments on the Environmental Analysis. However, as those documents were not published by CARB until September 21, 2015 my ability to review them has been very limited. I have performed this review 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. Turning first to the ADF regulation, the Proposed ADF regulation includes a NOx Significance Threshold that is substantially less stringent than the Threshold included in the "Preliminary Rulemaking Proposal for Biodiesel Use as an Alternative Diesel Fuel" dated July 29, 2014.[1] By relaxing the proposed NOx Significance Threshold, CARB increased the potential for the ADF regulation to result in significant and unmitigated adverse environmental impacts while reducing the cost of compliance for businesses involved in the selling and distribution of biodiesel in California. To the best of my knowledge, to date, despite numerous requests from Growth Energy, CARB has failed to explain the supporting basis for the relaxation in the NOx Significance Threshold or any analysis indicating the tradeoff CARB made between increased NOx emissions and reduced compliance costs for the biodiesel industry.

7. The change in the NOx Significance Threshold was apparently negotiated in private by CARB staff and representatives of the biodiesel industry. That this seems to be the case is supported by testimony from several biodiesel industry representatives at the February 19, 2015 public hearing. In this testimony, biodiesel industry representatives referred variously to the CARB's proposed ADF regulation as a "great"[2] or "grand"[3] compromise as well as a "well-crafted decision".[4] In addition, it appears that these negotiations directly involved CARB Executive Officer Richard Corey as evidenced by the testimony of another biodiesel industry representative who stated "I want to thank Mr. Corey for his personal involvement in this very important issue. He made a big impact in the direction of this regulation."[5] Again, to the best of my knowledge, to date, CARB has provided no information regarding the substance of these negotiations and as provided no technical basis for of analysis of its decision to relax the NOx Significance Threshold.

8. Turning to the LCFS regulation, as I noted in my declaration of August 17, 2015, I understand that CARB has failed to estimate the number of new or converted heavy-duty natural gas vehicles that will have come into use in California over the period from 2015 to 2025 in order to actually consume the amount of natural gas CARB staff

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[1] http://www.arb.ca.gov/fuels/diesel/altdiesel/20140729ADF_SRIA_Proposal.pdf.

[2] See the transcript of the February 19, 2015, Public Hearing at page 233, line 11.

[3] See the transcript of the February 19, 2015, Public Hearing at page 242, lines 12-23.

[4] See the transcript of the February 19, 2015, Public Hearing at page 237, lines 16-18.

[5] See the transcript of the February 19, 2015, Public Hearing at page 241, lines 17-20.

has assumed will be used in the state in its Illustrative Compliance Scenario. As I indicate in my previous declaration, CARB's failure to consider this issue seriously compromises both the Environmental Analysis and CARB's economic assessment of the LCFS regulation. My understanding that no natural gas vehicle estimates were made is based on a July 31, 2015 letter from Elaine Meckenstock (Exhibit B) and on other information requested under a public records act request—all of which fail to address these estimates because they do not exist.

9. As part of its "Third Notice of Public Availability of Modified Text and Availability of Additional Documents" dated July 31, 2015, CARB added a spreadsheet entitled "Estimate of Electricity Use by ZEVs" to the rulemaking file. This spreadsheet revealed for the first time the assumptions made by CARB staff in estimating the amount of electricity that would be used by light-duty battery electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) for the purposes of developing illustrative compliance scenarios and evaluating potential compliance curves as documented in Appendix B of the Initial Statement of Reasons (ISOR) and subsequent updates. As the most recent illustrative compliance scenario[6] shows, CARB is forecasting that LCFS credits generated by ZEVs will increase by more than nine times over the period from 2015 to 2025. By 2025 CARB forecasts that LCFS credits from ZEVs will account for 30% of all LCFS credits generated by gasoline substitutes.

10. Unfortunately, although CARB is forecasting that credits from ZEVs will play a major role with respect to LCFS compliance, under the proposed LCFS regulation, there will be no mechanism for verifying that credits granted for ZEVs will represent actual reductions in GHG emissions. As explained in Exhibit C, rather than the requiring the direct measurement of the actual quantity of a transportation fuel used in California as is the case for all other fuels, CARB is proposing to allow the use of "approximate" methods. These approximate methods could lead to the generation of substantial amounts of fictitious LCFS credits by Electric Distribution Utilities which would in turn would substantially reduce the environmental benefits of the LCFS regulation. This reduction in environmental benefits would result from an actual increase GHG emissions enabled through CARB's providing fictitious LCFS credits to ZEVs. Given that CARB forecasts that 3.352 million LCFS credits will be issued in 2025 and uses credit prices of between $40 and $100 to evaluate impacts, even a 10% overestimation of the amount of electricity used by ZEVs would result in a $13 to $33 million windfall for Electric Distribution Utilities just in 2025, and a 350,000 metric ton overestimation of the GHG reductions achieved by the LCFS regulation. Over the entire period from 2015 to 2025, this windfall would be between $66 and $166 million with the shortfall in GHG reductions being 1.6 million metric tons.

11. That LCFS credits for ZEVs could be fictitious can be seen from CARB's own admission that the agency needs to spend $650,000 on research in order to

[6] Analysis of Compliance Curve Reflecting the Impact of May 2015 Proposed 15-Day Changes," CARB, May 22, 2015.

understand how ZEVs will be used and recharged. CARB can eliminate any concern regarding the validity of LCFS credits provided for ZEVs by simply requiring direct quantification of the actual amount of electricity used by the vehicles, as is required by the proposed LCFS regulation for every other fuel except electricity.

12. In addition to providing LCFS credits for electricity used in ZEVs, the proposed LCFS regulation includes provisions that would allow LCFS credits to be generated by electric forklifts and "fixed guideway" systems. According to CARB,[7] a fixed guideway system:

> *is a system of public transit electric vehicles that can operate only on its own guideway (directly operated, or DO) constructed specifically for that purpose, such as light rail, heavy rail, cable car, street car, and trolley bus.*

Also using data provided by CARB,[8] the potential amount and the value of the resulting electric forklift LCFS credits over the period from 2015 to 2025 is about 450,000 metric tons and between $18 and $46 million. For fixed guideway systems over the same period, the potential LCFS credit amount is about 1.8 million metric tons and the value is between $73 and $183 million.

13. As with the LCFS credits being provided for the use of electricity by ZEVs, under the proposed LCFS regulation there are serious questions regarding the validity of the LCFS credits being provided to electric forklifts and fixed guideway systems. The basis for these questions include, 1) that direct measurement of electricity use in electric forklifts is not required and that LCFS credits can be based on estimates of electricity use, and 2) the fact that LCFS credits are being provided for electricity use in both applications, even though it is also included in the 2010 base year for the LCFS regulation.

14. As is the case with ZEVs, CARB is proposing to allow the use of a method for estimating the amount of electricity used by electric forklifts rather than requiring direct monitoring for purposes of issuing LCFS credits, at least for credit generation by Electric Distribution Utilities. However, inexplicably, if LCFS credits are to be issued to the actual owners and operators of the electric forklifts, then the agency requires that the actual amount of electricity used by the forklifts to be directly measured. That this is in fact the case can be seen in the language of proposed section 95491(a)(3)(D)7. Title 17 California Code of Regulations published by CARB staff on July 8, 2015.[9] Neither the ISOR nor the July 8 publications contain any explanation as to why direct measurement

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[7] See Page III-7 of the LCFS ISOR.

[8] See Pages III-9 and -10 of the LCFS ISOR

[9] See http://www.arb.ca.gov/regact/2015/lcfs2015/lcfsmodregorder.pdf.

of the electricity used by forklifts is required in order for operators of electric forklifts to generate LCFS credits, while estimates are acceptable for LCFS credit generation by Electric Distribution Utilities. Again, CARB's allowance of the use of estimation methods rather than direct measurements of energy use by electric forklifts creates the potential for the creation of fictitious LCFS credits, which could be easily eliminated by simply requiring direct quantification as CARB is requiring for every other fuel under the LCFS.

15. In the case of electric forklifts and fixed guideway systems, under the proposed LCFS regulation, LCFS credits will be provided despite the fact that electricity was already being used as a fuel for these applications in 2010. That this is in fact the case can been seen from CARB's discussion of the credits being provided to electric forklifts and fixed guideway systems.[10] CARB's proposal for providing LCFS credits for electricity used in electric forklifts and fixed guideway systems where electricity was already being used in 2010 is fundamentally inconsistent with the treatment of other alternative fuels under the proposed LCFS regulation. Specifically, as previously pointed out by Growth Energy in April 2014 (See Exhibit D and the related CARB "LCFS Concept Paper which is Exhibit E), CARB's inclusion of ethanol, which was being added to gasoline in California in 2010, in determining the baseline carbon intensity value for gasoline is completely at odds with CARB's treatment of electricity used in forklifts and fixed guideway systems. In order to be consistent, CARB should establish the 2010 baseline gasoline carbon intensity value without including ethanol.

16. If CARB proceeds without excluding ethanol from the 2010 baseline gasoline carbon intensity value, than CARB must also eliminate the provision of LCFS credits for electricity that was being used as a transportation fuel in 2010 in order to be consistent in its treatment of alternative fuels. I would also note that CARB claims to have remedied this inconsistency by reducing the amount of LCFS credits that are provided to electric forklifts and fixed guideway systems; however, no analysis is provided that demonstrates that the LCFS has or will have any impact on the amount of electricity used in these applications. In fact, CARB's Compliance Curve[11] shows the amount of electricity assumed to be used in heavy-duty vehicles and rail to be constant each year from 2016, when credits would first be available, through 2025—meaning that CARB itself expects no increase in the use of electricity relative to 2010 levels to occur as a result of the LCFS regulation. Unless CARB can specifically demonstrate that the LCFS is resulting in increased use of electricity in forklifts and fixed guideway systems, no LCFS credits should be provided; and in the event increased use can be demonstrated, LCFS credits should only be made available for the incremental increase in electricity in these applications since 2010.

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[10] See pages III-7 to III-10 of the LCFS ISOR.

[11] Analysis of Compliance Curve Reflecting the Impact of May 2015 Proposed 15-Day Changes," CARB, May 22, 2015.

17. As noted above, given that the final EA and Response to Comments on the EA were only published by CARB on September 21, my review of those documents is preliminary at this time. However, based on the review that I have performed, I find that in general CARB has failed to address my comments and failed to present any data or analysis that refutes the analysis that I have performed. Rather, in responding to my comments, CARB has simply restated their original flawed arguments and asserted, without meaningful support, that CARB is correct.

18. For example, CARB does not dispute that biodiesel that has been, or is currently being, used under the 2009 LCFS regulation has led to increased NOx emissions, or that biodiesel used under the Proposed LCFS regulation will also lead to unmitigated increases in NOx emissions. That this is in fact the case can be clearly seen in Table 1 of the 15-Day Notice for the ADF regulation.[12] As shown, the unmitigated NOx increases in 2014 and 2015 due to biodiesel under the 2009 LCFS regulation are reported by CARB to be 1.19 and 1.10 tons per day respectively, with unmitigated increases in NOx emissions from biodiesel use continuing under the proposed LCFS regulation until 2020, despite the use of CARB's flawed assumptions and methodologies.

19. Another example can be seen in EA Responses ADF 17-4 and B3-162 where CARB continues to claim that data from NTDEs with retrofit systems should not be included in assessing the impacts of biodiesel use on NOx emissions from NTDEs while failing to acknowledge that vehicles equipped with retrofit systems are clearly defined as NTDEs under proposed §2293.2(a)(18)(C) of Title 13, California Code of Regulations. Further, despite the substantial increases in NOx emissions that my analysis indicates could result from biodiesel use, CARB intends as indicated in EA Response ADF 17-4, to put off any further consideration of the impact of biodiesel on NOx emissions from NTDE's until December, 2019.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 23th day of September, 2015 at Sacramento, California.

JAMES M. LYONS

[12] See http://www.arb.ca.gov/regact/2015/adf2015/signedadfnotice.pdf.

EXHIBIT A to Declaration of James M. Lyons

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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.

"Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle," Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

"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.

"Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies," Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

"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.

"Review of CO Compliance Status in Selected Western Areas," Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

"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.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

"Potential Evaporative Emission Impacts Associated with the Introduction of Ethanol-Gasoline Blends in California," Sierra Research Report No. SR00-01-01, prepared for the American Methanol Institute, January 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," SAE Paper No. 1999-01-3676, August 1999.

"Future Diesel-Fueled Engine Emission Control Technologies and Their Implications for Diesel Fuel Properties," Sierra Research Report No. SR99-08-01, prepared for the American Petroleum Institute, August 1999.

"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

"Analysis of New Motor Vehicle Issues in the Canadian Government's Foundation Paper on Climate Change – Transportation Sector," Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

"Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences," Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

"Costs, Benefits, and Cost-Effectiveness of CARB's Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal," Sierra Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

"Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona," Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

"Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies," prepared for Environment Canada, July 1997.

"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.

"Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada," Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

"Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"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.

"Phase II Feasibility Study: Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley," Sierra Research Report No. SR94-09-02, prepared for the Greater Vancouver Regional District, September 1994.

"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.

"Investigation of MOBILE5a Emission Factors, Assessment of I/M Program and LEV Program Emission Benefits," Sierra Research Report No. SR94-06-05, prepared for American Petroleum Institute, June 1994.

"Cost-Effectiveness of the California Low Emission Vehicle Standards," SAE Paper No. 940471, 1994.

"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

"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.

EXHIBIT B to Declaration of James M. Lyons

KAMALA D. HARRIS
Attorney General

State of California
DEPARTMENT OF JUSTICE

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July 31, 2015

VIA ELECTRONIC MAIL

Michael V. Brady
Brady & Vinding
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Sacramento, CA 95814

Stuart Drake
Kirkland & Ellis
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Washington, D.C. 20005

RE: *Farley v. ARB* (Case No. 34-2015-80002044)

Dear Mr. Brady and Mr. Drake:

As you and/or Growth Energy may already be aware, ARB issued a 15-day notice in the LCFS regulatory proceeding today. That notice was accompanied by two pieces of information that, as I understand it, substantially, if not completely, address two of the three parts of Growth Energy's proposed new PRA request that has become the subject of these negotiations:

1. A document showing the calculation, described in Appendix B to the ISOR, for the "Electricity for LDVs" values in the illustrative compliance scenario.

2. The Rosas-Perez data—the data referred to as "[t]he data set used" by Dr. David Rocke at page 5 in his report titled "Statistical Issues Related to the Low-Carbon Fuel Standard" (dated October 31, 2014).

I believe the parties should discuss the implications of this development for Growth Energy's proposed new PRA request. I am unfortunately traveling much of the day today but have more flexibility Monday and Tuesday of next week. Please let me know a time or two that would work for you on those days, and I will try to make those work on my end as well.

To facilitate our next conversation, I offer a few thoughts below, grouped by the part numbers from your latest draft PRA request.

Part 1

In our call on the afternoon of Monday, July 27, 2015, you expressed Growth Energy's interest in several specific aspects of the illustrative scenarios that appear as Tables B-22, B-23 and B-24 in Appendix B of the Initial Statement of Reasons for the Proposed Rulemaking to Re-Adopt the Low Carbon Fuel Standard Regulation dated December 2014 ("the ISOR") and updated versions of those tables that ARB has publicly released since the ISOR. You indicated Growth Energy sought 1) any estimates of battery-electric vehicles or plug-in hybrid electric vehicles ARB made in order to produce the electricity-usage estimates in the illustrative scenarios; 2) any estimates ARB made concerning the percentage of E85 in order to produce the illustrative scenarios; and 3) the calculation, if any, ARB performed that produced the average carbon intensities for corn and cane ethanol in 2016 (70 and 44, respectively in the May 22 scenario). Before the call you sent us several excerpts from previous ARB publications containing, *inter alia*, estimates of electric vehicles and percentages of E85 in the gasoline pool. On the call, you indicated that these excerpts represented the kind of information Growth Energy sought.[1]

As explained in Appendix B to the ISOR, the values in the illustrative scenarios are not derived from vehicle estimates other than those publicly available; nor are they derived from estimates of percentages that E85 might comprise of the gasoline pool. Further, the average carbon intensity estimates for 2016 for corn and cane ethanol reflect the calculation described in Appendix B to the ISOR and adjustments in the GREET model described at ARB's April 3, 2015 workshop and in the First Notice of Public Availability of Modified Text and Availability of Additional Documents. Since the information concerning the topics discussed on our call all appears to be publicly available, there may be little value in continuing to negotiate over a possible PRA request related to the illustrative compliance scenarios. We are interested in whether you agree.

Part 3

As with Part 1, there seems to be little value in continuing to negotiate language of a possible PRA request for Growth Energy to obtain the publicly available Rosas-Perez data. Again, we are interested in whether you agree.

[1] Your latest draft request, sent at 4:26 PM on July 28, 2015, seems to expand significantly the scope of a potential PRA request compared to what was discussed on the call the day before. Most notably, the latest draft request does not simply seek any estimates of vehicle numbers (as appear in the excerpts you sent) but rather "factual information or analysis used to prepare or relied upon to prepare" any such estimates. Further, the draft request seeks information to which there was no reference on the call (or in the excerpts you sent just before it), including information about heavy-duty vehicles. On the call, you also indicated no interest in the hydrogen figures in the illustrative scenarios, noting that they are very minor. Yet, the new draft request you sent seeks information about those very figures (subpart 1(e)). In addition to expanding the scope of information well beyond what was discussed on our call, the latest draft request still contains language ARB has already objected to—most notably the phrase "relied upon."

Part 2

As discussed above, it seems the parties should focus on negotiating the language for Part 2 of Growth Energy's proposed PRA request. As I have previously indicated, ARB is unwilling to agree to a request that defines records or information or analyses in terms of ARB having "relied upon" them. Indeed, with respect to the proposed ADF regulation described in the ISOR released in December 2014, the information ARB relied on is already publicly available in the rulemaking file. ARB sees little, if any, reason to agree to provide information that is already public.

Focusing on the other component of Part 2 of Growth Energy's proposed request, ARB is willing to treat the following as a new PRA request and to respond expeditiously to it, without waiving any rights or privileges (including the right to withhold exempt records):

> All records that constitute factual information or analysis that formed the basis for the approach to mitigating NOx emissions from biodiesel that was described in ARB staff's "Preliminary Rulemaking Proposal for Biodiesel Use as an Alternative Diesel Fuel" (made public on or around July 29, 2014 and available at http://www.arb.ca.gov/fuels/diesel/altdiesel/20140729ADF_SRIA_Proposal.pdf). This request does not include factual information and analysis that is publicly available (for example, factual information and analysis in the rulemaking file for the ADF regulation proposed by the staff in December 2014).

If the request above is acceptable to Growth Energy, or other text can be agreed upon fairly soon, ARB is prepared to discuss a reasonable schedule by which it would respond, with the understanding that Petitioners would agree to dismiss the current *Farley* lawsuit with prejudice.

I look forward to speaking with you soon.

Sincerely,

/s/ M. Elaine Meckenstock
M. ELAINE MECKENSTOCK
Deputy Attorney General

For KAMALA D. HARRIS
Attorney General

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EXHIBIT C to Declaration of James M. Lyons

Critical Review of CARB Staff Requirements for Ensuring the Validity of LCFS Credits Generated by ZEVs

In developing the proposed Low Carbon Fuel Standard (LCFS) regulation for re-adoption, CARB staff is proposing to allow the amount of electricity supplied to electric vehicles during recharging at households and residences be determined via "estimation methods" subject to approval by the Executive Officer, rather than the use of the definitive method of direct metering. As is documented below, CARB staff's failure to require direct metering creates the potential for LCFS credits to be provided in cases where electricity was not actually used as a transportation fuel. Clearly, the potential for the generation of invalid LCFS credits is unacceptable, in any case, much less in the case of electric vehicles which CARB staff itself estimates[1] will consume 10 times as much energy in 2025 than in 2015 and be responsible for in excess of 9 times more LCFS credits in 2025 than in 2015. In order to ensure that LCFS credits are valid, CARB staff must require direct metering of all electricity supplied to electric vehicles, just as it requires direct accounting for the volume usage of all other transportation fuels for which LCFS credits and debits are issued.

Critical Review of the CARB Requirements for Determining the Actual Amount of Electricity Used in Electric Vehicles Recharged at Households and Residences

As noted on pages II-29 and II-30 of the LCFS ISOR, CARB staff is proposing to extend current requirements that "allow electricity providers for residential EV charging to, upon Executive Officer approval, use a method to ***approximate***[2] residential EV charging electricity" beyond the end of 2014 as indicated in proposed section 95491(a)(3)(D)1.b. Title 17, CCR. In justifying this proposal, CARB staff states:

> *The estimation method currently being used by some utilities is based on all available directly metered data in each utility's service territory, the California Vehicle Rebate Project database, and California Department of Motor Vehicles registration data. The number of credits generated through an estimation method is not expected to differ significantly from the number of credits generated solely through the reporting of metered data (if all EV drivers employed dedicated metering to measure their charging electricity).*

However, CARB staff provides absolutely no supporting basis for the conclusion that the number of credits generated using estimation methods will not differ "significantly" from those that would be generated if direct metering were required. Further, CARB staff fails to provide any quantitative indication of what it would consider to be a significant difference between LCFS credits provided via estimation methods for electricity use in EVs versus actual usage determined

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[1] Analysis of Compliance Curve Reflecting the Impact of May 2015 Proposed 15-Day Changes," CARB, May 22, 2015.

[2] Emphasis added.

through direct metering. In addition, CARB staff fails to provide in the ISOR and its appendices any insight into the methodology and criteria that the Executive Officer will use to evaluate proposed estimation methods for approval, or the analysis that lead to the approval of the current estimation methodology.

Concerns with CARB staff's failure to disclose any of the above information are heightened by the fact that the agency has proposed to initiate a $650,000 research program that CARB staff claims is necessary because:[3]

> *How consumers use and charge/refuel their advanced technology vehicles is not well understood, especially given the increasing diversity of vehicle designs and driving ranges. Vehicle charging/refueling and usage behavior will likely vary depending on the type of vehicle technology (e.g., different battery capacities and architecture) or age of the vehicle (e.g., in response to battery deterioration).*

How the Executive Officer of an agency that does not currently understand well how plug-in electric and pure electric vehicles are used and charged can be relied upon to approve estimation methodologies for the generation of LCFS credits, while ensuring that the results are not significantly different from those resulting from direct metering of electricity use, is not explained by CARB staff in the LCFS ISOR or its appendices and supporting documents. Again, the need to ensure that LCFS credits provided for electricity use as a transportation fuel are real is key, given the massive increase in LCFS credits the staff expects to be awarded for electricity use between now and 2020, as evidenced in May 22 Compliance Curve. Allowing the generation of fictitious LCFS credits for electricity use also adversely impacts providers of other lower CI transportation fuels whose "real" LCFS credits will be devalued.

That CARB staff clearly understands the superiority of direct metering to estimation methods, and intends to limit the use of estimation methods, can be seen from discussions on pages V-13 and 14 and X-6 of the 2009 LCFS ISOR, which include consideration of the application of discount factors to electricity usage values derived from estimation methods.

In order to ensure the validity LCFS credits awarded for electricity usage, CARB staff should require direct metering or provide a quantitative analysis demonstrating that estimation methods can be relied upon. To the extent that credits are allowed to be generated through the use of estimation methods, substantial discount factors should be applied both to account for uncertainties in the estimation methods, and to provide an incentive for the use of more accurate direct metering.

[3] California Air Resources Board, Annual Research Plan: Fiscal Year 2015-2016, December, 2014.

EXHIBIT D to Declaration of James M. Lyons

Comments of Growth Energy on the Air Resources Board Staff Presentations at a Public Consultation Meeting on the California Low-Carbon Fuel Standard Regulation

These comments respond to the ARB staff's request for comments on the staff's presentations at the March 11, 2014 public consultation meeting on the proposed adoption of a new version of the California low-carbon fuel standard ("LCFS") regulation.[1] These comments address three main subjects: (1) the proposed establishment of two "tiers" for alternative fuel pathways, (2) issues raised by the proposed treatment of electricity in the diesel compliance strategies, and (3) the staff's new analysis of indirect land-use change ("ILUC") emissions factors. The comments on the ILUC emissions factors are contained in an Appendix to these comments, prepared by Air Improvement Resource, Inc.

Before turning to the main subject of these comments, it is important to note that, at present, the staff has not explained fully how it intends to conduct the environmental assessment of the proposed new LCFS regulation. In that assessment, ARB must include a scenario in which the Board would rely on the Advanced Clean Cars regulation, Phase 1 and 2 greenhouse gas ("GHG") regulations for heavy- and medium-duty vehicles, and the federal Renewable Fuel Standard and other existing measures to achieve reductions in GHG emissions from the transportation sectors.

In performing these environmental assessments, ARB must address all reasonable means by which regulated entities could comply with each of the regulatory scenarios considered as well as the secondary consequences of those pathways. For example, if regulated entities might

[1] Growth Energy is among the plaintiffs in the litigation challenging the current version of the LCFS regulation. Because ARB is now contemplating adoption of a new LCFS regulation, Growth Energy is continuing its participation in the rulemaking process while it pursues its federal legal challenge to the currently adopted LCFS regulation.

purchase all the cellulosic ethanol produced in the United States for use in California, the environmental assessment must include not only the impacts associated with the transport of that ethanol to California, but also the transport of ethanol that has been displaced by cellulosic ethanol from California to where it is ultimately consumed.

The environmental assessment must also consider the broader impacts of the regulation, not just the life-cycle GHG emissions that ARB estimates to be associated with the fuels. For example, if ARB believes that LCFS compliance might be achieved in any significant part through increased use of electricity and hydrogen as transportation fuels, then the environmental analysis must also consider the differences in life-cycle GHG emissions associated with the production of vehicles capable of operating on electricity and hydrogen compared to the vehicles that would have otherwise been operating in the state. Similarly, the analysis must consider the life-cycle GHG impacts associated with factors such as the production and installation of refueling infrastructure, as well as the production and disposal of original and replacement batteries used in electric propulsion systems.[2]

In addition, the environmental assessment must avoid "double counting" of potential emissions reductions. Notably, the lifecycle GHG reductions associated with the use of electricity as a transportation fuel have already been claimed in assessing the GHG emissions associated with the vehicle under the Advanced Clean Cars Regulation.

[2] All potential impacts must be identified in the assessment, and measures to mitigate those impacts must be considered. Potential impacts could include those associated with the construction and operation of electricity generation and other fuel production facilities, increases in emissions from marine vessels and port operations associated with biofuel importation, increases in vehicular exhaust or evaporative emissions associated with the use of non-petroleum fuels, effects of higher prices for new vehicles and transportation fuels, and reductions in the effectiveness of other California environmental regulations.

I. Definition of Two Tiers for Alternative Fuel Pathways

There are a number of serious issues associated with the staff's proposed new approach to assigning carbon intensity ("CI") values to alternative fuel pathways. Those issues include the following:

- Penalizing or rewarding of producers of some fuels by assigning production pathway CI values that differ from the actual pathway CI values through the proposed "binning" procedure for "Tier 1" fuel pathways[3] in order to reduce the work load imposed by the LCFS regulation on ARB staff.

- Providing preferential treatment to some fuel production pathways defined by ARB as "Tier 2"[4] by assigning actual pathway CI values to those fuels rather than subjecting them to the "binning" procedure proposed for application to "Tier 1" fuels.

In addition, along with the actions being proposed with respect to creating CA-GREET 2.0 and revising pathway CI values, ARB must carefully reassess all internal ARB-developed fuel pathways to ensure that they are based on the latest available data and have been subjected to the same rigorous review that ARB has applied to pathways approved under the Method 2A/2B process.

Beginning with the binning procedure for Tier 1 fuel pathways, although the details are far from clear, ARB staff has indicated that it will propose CI bins that span a range of gCO2e/MJ values: all fuel pathways falling into a given bin would receive the same CI value, which would be set equal to the midpoint value of the bin. For example, if a given bin spanned the 7 gCO2e/MJ range from 61 to 67 gCO2e/MJ, all fuel pathways assigned to that bin would receive a CI value of 64 gCO2e/MJ. This means that the producer of a fuel with an actual pathway value of 66.9 gCO2e/MJ would be assigned an LCFS CI value of 64 gCO2e/MJ

[3] Tier 1 fuels have been loosely defined to date by ARB as "first-generation fuels, such as starch- and sugar-based ethanol...."

[4] Tier 2 fuels have been loosely defined to date by ARB as "next-generation fuels, such as cellulosic alcohols" as well as fuels produced using "an innovative method...."

(approximately 4% lower than actual) and a credit of 2.9 gCO2e/MJ for each MJ of fuel produced. In contrast, a producer of a fuel with an actual pathway value of 61.1 gCO2e/MJ would be assigned an LCFS CI value of 64 gCO2e/MJ (approximately 5% higher than actual) and a deficit of 2.9 gCO2e/MJ for each MJ of fuel produced. To date, the staff has provided no technical rationale for this approach, and justified it based only on claims that it is necessary to reduce the burden placed on ARB staff to review and approve new CI values.

While the assignment of actual CI values for Tier 2 pathways is technically correct, it is obviously inconsistent with the treatment of Tier 1 pathways and the policy of "fuel neutrality." Furthermore, it clearly discriminates against producers of Tier 1 fuels in favor of producers of Tier 2 fuels. It is also inconsistent with ARB's proposed treatment of CI reductions resulting from the use of "innovative technologies for crude oil production" where the current 1 gCO2e/MJ threshold for receiving credits would be eliminated. It is unclear why ARB staff preferentially values small reductions in the CI of crude oil production, but is willing to assign CI values for Tier 1 fuel pathways that differ from actual CI values by much larger amounts. ARB needs to ensure that the LCFS regulation equitably addresses the CI values assigned to all fuel production pathways. To the extent that ARB finds itself unduly burdened by the regulatory process it has created to assign pathway CI values, it is the responsibility of the agency—not producers of Tier 1 fuels—to find additional resources or identify means to simplify the regulatory process.

The ARB staff is also proposing to create a new version of the CA-GREET model used in determining CI values. According to the staff, the new version will be known as CA-GREET 2.0 and will incorporate updates based on changes that have been made to the GREET model by Argonne National Laboratory since the development of previous version (CA-GREET1.8b), as

well as an updated electricity mix and other changes. As part of this process, ARB must conduct rigorous and objective reviews of all internal ARB-developed fuel pathways similar to those performed for pathways approved under the Method 2A/2B process.

Of particular importance are the pathways internally developed by ARB that apply to California electricity and Brazilian sugarcane ethanol. With respect to California electricity, ARB must ensure that the same level of detail and attention that is being applied to update the electricity mix for the U.S. for use in CA-GREET 2.0 is also applied to the internal pathways used to assign CI values for California electricity. Similarly, ARB must review the CI values that apply to Brazilian sugarcane ethanol based on the existing internal pathways with the same level of scrutiny applied to the Method 2A/2B applications that have been submitted by U.S. producers of corn ethanol. ARB has reviewed and approved scores of pathway Method 2A/2B applications for corn ethanol pathways with CI values lower than those available from the internal ARB pathways. During this process, ARB requires applicants to submit detailed data and documentation substantiating the actual CI values that have been applied to these pathways. In contrast, all of the CI values currently available for Brazilian sugarcane ethanol are based on ARB's internal pathways derived from the limited number of life-cycle analyses available in the technical literature, which are based on limited generic data and have required numerous assumptions. This situation is not going to be remedied by relying on updates to the GREET model made by Argonne since the finalization of CA-GREET 1.8b, given that the most recent update[5] to the Brazilian sugarcane pathways in GREET continues to rely on what appears to be limited data and aggregated data. Further, the basic data do not appear to have been made available to ARB for the same kind of review and scrutiny applied to data from U.S. corn ethanol

[5] "Updated Sugarcane Parameters in GREET1_2012," Second Revision, Han, J., Dunn, J.B., Cai, H., Elgowainy, A., and Wang, M.Q., Argonne National Laboratory, December 2012.

plants or made available to the public at the level of detail required by the Method 2A/2B process. The need for this review is further underscored by the lack of Method2A/2B applications for Brazilian sugarcane ethanol, the absence of which suggests that the CI values assigned by the ARB internal pathways are lower than those that would be assigned based on facility-specific data.

Finally, it is important to note that the staff's proposed binning approach for ethanol is inconsistent with its proposal to provide credit under the LCFS regulations to gasoline refineries with no minimum CI reduction required. The differing treatment of gasoline and ethanol cannot be justified.

II. Treatment of Alternative Fuels in the Baseline.

During the process leading to the adoption of the LCFS regulation in 2009, ARB defined the gasoline baseline as a fuel consisting of 90% CARBOB and 10% ethanol produced using the mid-west average corn ethanol pathway instead of correctly defining it as a pure hydrocarbon fuel. The following passage from the 2009 Final Statement of Reasons explains ARB's reasoning:

> *Comment: ... [W]e encourage ARB to revisit its decision to use 2010 E10 as the baseline gasoline. Inclusion of 10% corn ethanol in the baseline gasoline formulation forces corn ethanol to compete against itself, rather than petroleum fuels with higher carbon intensity. ... [I]f ARB finds that the carbon intensity of corn ethanol is less than gasoline (due to justifiable adjustments to LUC and GREET analyses), this change in baseline date is not justified or desired, because increasing ethanol content from E5.7 to E10 would actually reduce overall blend carbon intensity.*
>
> *Response: The baseline ... includes 10 percent ethanol to reflect the ethanol content in CaRFG that will exist in January 2010. In evaluating the baseline carbon intensity, it was determined that the baseline value was basically the same whether 5.7 percent or 10 percent ethanol was used. Ten percent ethanol was also used because the predictive model in the CaRFG regulations as amended in 2007 requires that increases in evaporative*

hydrocarbons from the use of ethanol be mitigated. This can be done by using no ethanol or using more than the current 6 percent ethanol. Due to the Federal requirements to use more ethanol, producers are electing to use this approach. The consideration of the 2010 timeline was based on the Governor's Executive Order and not to satisfy any other requirement.

The Executive Order (EO) to which the ARB response refers establishes only a 2020 carbon intensity reduction target and nowhere mentions that the target should be linked to a 2010 baseline.[6] The EO undercuts ARB's selection of a 2010 baseline, given that it was issued in 2007, makes reference to the need for the LCFS regulation in light of the 2005 California vehicle fleet, and required the Secretary for Environmental Protection to report to the Governor as early as January 2008 regarding progress being made to achieve the 2020 target. Further, ARB's interpretation of the EO is also contradicted by the 2004 baseline year selected by the University of California in performing the technical and policy analyses[7,8] specified by the EO, and ARB's initial position during the course of the LCFS rulemaking where staff selected 2006 as the baseline year.[9]

The position taken in the 2009 rulemaking is further undercut in light of the improvements to the ILUC value for corn ethanol since 2009. Table 1 presents the CI values for gasoline at different assumed ethanol concentrations, based on the assumptions that the current CARBOB CI value of 99.18 gCO2e/MJ applies and that the reduction in the ILUC value for corn

[6] Executive Order, S-01-07, 1/18/2007.

[7] Farrell. A.E., and Sperling D., "A Low-Carbon Fuel Standard for California, Part 1: Technical Analysis," August 1, 2007. Available at http://escholarship.org/uc/item/6j67z9w6

[8] Farrell. A.E., and Sperling D., "A Low-Carbon Fuel Standard for California, Part 2: Policy Analysis," August 2, 2007. Available at http://www.escholarship.org/uc/item/8xv635dc

[9] *See* http://www.arb.ca.gov/fuels/lcfs/122007arb_prstn.pdf

under consideration by ARB[10] will result in a CI value for Midwest average ethanol between 89.40 and 79.40 gCO2e/MJ.

Table 1. Effect of Adding Midwest Average Ethanol to Baseline Gasoline		
Ethanol Content (vol%)	Gasoline CI (gCO2e/MJ) and Reduction in CI relative to E0 if Midwest Corn Ethanol CI = 89.40	Gasoline CI (gCO2e/MJ) and Reduction in CI relative to E0 if Midwest Corn Ethanol CI = 79.40
0	99.18 - 0.0%	99.18 – 0.0%
5.7	98.79 - 0.4%	98.40 – 0.8%
10	98.49 - 0.7%	97.79 – 1.4%
15	98.13 - 1.1%	97.06 – 2.1%

As shown in Table 1, the addition of Midwest average ethanol to gasoline does in fact have a substantial impact in reducing CI, with the magnitude of the reduction becoming larger as more ethanol is added.

ARB's inclusion of ethanol in the gasoline baseline in 2009 failed to acknowledge the reasons why ethanol had come to widespread use in gasoline in California. Those reasons include the oxygenate requirement that was part of the federal Reformulated Gasoline regulation and the federal Renewable Fuel Standard regulation. The inclusion of ethanol in the gasoline baseline penalizes ethanol for having been recognized many years ago to be environmentally beneficial. Rather than penalizing ethanol for its early arrival in the marketplace, ARB should be providing retroactive credits for the GHG reductions that the use of ethanol achieved even before the LCFS regulation took effect. The continued inclusion of Midwest corn ethanol would discriminate against corn ethanol producers by depriving them of credits that they should be

[10] *See* http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/iluc_presentation_031014.pdf

awarded under the LCFS regulation, and prevents those credits from being available to aid regulated entities in complying with the LCFS regulation.

A comparison with the treatment of electricity in diesel-based compliance strategies is instructive. The relevant section of the staff Concept Paper released prior to the March 11 workshop states as follows (emphasis added):

> *The second alternative considered by staff involves modifying the 2010 baseline to include alternative fuel use. In this analysis, staff first determined the fuel use of transit and non-transit natural gas, transit electricity and electric forklifts in 2010. Next the carbon intensity of these fuels was incorporated into the 2010 diesel standard based on each fuel's portion of the total fuel pool (diesel and diesel replacements). A revised diesel standard was determined, and corresponding annual standards calculated, to reflect the revision. Including alternative fuel use in the baseline lowers the 2010 diesel standard by approximately 2 gCO2e/MJ and subsequent standards for 2015-2020 by approximately 1 gCO2e/MJ. This standard adjustment would increase diesel deficits and decrease alternative fuel credits compared to the current program. Staff presented the results of this analysis at a public workshop in April 2013 and thereafter considered stakeholder feedback.* ***Staff chose not to pursue the baseline approach because compliance with the diesel standard would become more difficult with no corresponding benefit to the alternative fuel market.*** *In addition, because these credits would be generated only if regulated parties opt-in to the program and report electricity use, a change to standards based on potential credit generation would be unfair to diesel regulated parties. This recommendation was subsequently presented at a public workshop in May 2013.*

Of course, the same rationale requires that ethanol be excluded from the gasoline baseline. There is certainly no basis to treat Midwest corn ethanol differently than how ARB is proposing to treat electricity. Removing Midwest ethanol from the gasoline baseline would appropriately credit producers, promote competition, and minimize regulatory costs.

Respectfully submitted,

GROWTH ENERGY.

APPENDIX

Comments on ARB's March 11 Workshop on Indirect Land-Use Change Emissions

Prepared by Air Improvement Resource, Inc.

The ARB staff proposes to use 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.

Global Trade Analysis Project (GTAP)

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 (no land use change emissions).

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.[1] None of these three ways involves a land use change or land use change emissions. Furthermore, GTAP does not include these three 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 three factors on crop production can be estimated by comparing trends in total harvested area to total cropland.

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

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 three 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.[2] 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 ARB'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.[3] 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. ARB appears to concur with this timeframe for GTAP, because ARB describes the model as a "Current" model, meaning that its estimates are applicable to the 2013/2014 timeframe, even though its primary data is for 2004.[4]

ARB, however, performed sensitivity analyses using price-yield elasticity values from 0.05-0.30 (20%-120% of the default value). ARB'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

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

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

[4] See page 57 of the ARB March 11 Workshop Briefing, iluc_presentation_handouts_031014.pdf.

parameter to use in modeling. Furthermore, ARB did not consider the analysis by Ray and Foley in determining the range of price-yield values to use.

ARB 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, ARB 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, but 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 the Ray and Foley analysis referenced earlier.

ETL1 and ETL2 Values

ARB 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.
ARB appears to have used some, but not all, ETL1 and ETL2 values from a 2013 Applied Science paper by Taheripour and Tyner. [5] 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 ARB are shown in Table 1 below.

Table 1. Differences in ETL1 and ETL2 Values Between ARB and Purdue

Region	Purdue – Applied Sciences 2013		ARB	
	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

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

It is not clear why ARB departed from the ETL1 and ETL2 values developed by Purdue, and what analysis or data ARB based these values on. An explanation of this should be provided for review, or ARB should use the tuned 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.* (emphasis added)

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, such as the one developed by Taheripor and Tyner in the Applied Science paper. The fact that forest is more costly to convert to crops than pasture almost needs no explanation. However, Taheripor and Tyner point out that

> *Gugel et al have shown that in general pastureland rent is higher than forest land rent, and both of these land rents are smaller than cropland rent across the world except in a few places. This means that the net costs of converting pastureland to crop production should be less than the net costs of converting forest to cropland. Putting forest, pasture, and cropland in the same nest ignores this important fact.*

Taheripour and Tyner altered the land cover component of the land supply tree to have forest and pasture land in two different nests. They also developed new ETl1 and ETL2 values, tuning these to historical land use changes. They split the ETL1 into an ETL1 for pasture and an ETL1 for forest (i.e., $ETL1_f$, and $ETL1_p$). They made the ETL_f only 20% higher than ETL_p. 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.*

To show how important these changes were, the authors modeled the US ethanol program, estimating land transitions. With the new ETL1 and ETL2 values, predicted global net forest conversions were reduced from 303,000 ha to 241,000 ha. When the forest/pasture nesting changes were made, however, predicted global net forest conversions dropped from 241,000 ha to 75,000 ha. Forest conversions are the factor that drives 75% of LUC emissions in estimating LUC emissions of biofuels.

ARB 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 ARB in early 2013. ARB 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 USA and Brazil (ARB 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. [6] These data show over 10 million acres of CRP land have gone back into production. These are not US 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.

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

[6] "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.

AEZ-EF Model

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 ARB 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. ARB 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.[7] 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, ARB 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, ARB should also account for wood mass that is used for fuel during forest clearing. Wood that is burned to produce energy (for a sawmill, for example) is replacing fossil-fueled energy, and is renewable. ARB does not count CO_2 emissions from facilities that use waste wood to produce energy for fuel production (ARB does, however, count non-CO_2 GHG emissions, which is appropriate). Heath et al estimate that 35% of carbon from forest clearing is used for energy.[8] In the US, Canada, and the EU27, ARB should not count the CO_2 from wood used to produce energy.

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[7] 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.

[8] 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.

CCLUB Model

ARB should consider using the CCLUB (Carbon Calculator for Land Use Change from Biofuels Production) model for estimating emissions.[9] 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.[10,11] Third, it allows the user to input HWP fractions, and fourth, it does not count CO_2 from the forest wood used to produce energy. For areas outside of the US, it utilizes Winrock emissions.

ARB 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 ARB's estimates.

Updated LUC Modeling

AIR downloaded ARB's GTAP model and the AEZ-EF model to determine the impacts of some of our suggestions. 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 Average 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

[9] 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.

[10] 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.

[11] 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/

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

- ARB's ETL1 and ETL2 values
- Model Nesting Structure and additional tuned ETL1 values
- Price-Yield Range
- Include US CRP conversions
- Include CCLUB emissions

It is clearly impractical for us to run the model 1440 times to test the impact of these five~~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 19.87 gCO2e/MJ. We then reduced the price yield elasticity from 0.175 to 0.1263, and obtained emissions of 23.21 gCO2e/MJ, which is the same as ARB's corn ethanol estimate. This is our single run that generally represents ARB's 1440 cases (i.e., the AIR "Representative" case).

- To test ARB's ETL1 and ETL2 values, we inputted Purdue's ETL1 and ETL2 values into ARB's GTAP model, and estimated LUC emissions.

- To test the model nesting structure change, we used the GTAP model provided by Purdue for work by AIR and others for the European Biodiesel Board (EBB), which is the same as the Purdue Applied Science Model, but with additional changes for the European Union such as disaggregated oilseeds, and

disaggregated coarse grains.[12] All other inputs were the same as the ARB inputs for ARB's model, including price-yield at 0.1263.

- To test the price-yield value, using the EBB GTAP model with the above ARB inputs, we increased the price-yield value to the Purdue default value of 0.25.
- To test the CRP impact, we activated the CRP code in the EBB-GTAP model.
- To test the CCLUB emissions impact we turned off the CRP activation and used CCLUB emissions instead of AEZ-EF.

The impact of the five changes on LUC emissions for the corn ethanol shock are shown in Table 5. The changes are all cumulative except for the last change (CCLUB), which includes the first three changes but does not convert CRP in the US.

Table 5. Impacts of Changes in GTAP Modeling (Corn Ethanol Shock in the US)

Scenario	Model	Emissions	LUC Emissions (gCO2e/MJ)
AIR "Representative" Case (ARB model, Price-yield = 0.1263)	ARB-GTAP	AEZ-EF	23.21
Change ETL1 and ETL2 parameters to Purdue "tuned" values from Applied Science 2013	ARB-GTAP	AEZ-EF	21.03
Implement Purdue GTAP Nesting Structure with Tuned Forest and Pasture ETL1 Elasticities, from Applied Science 2013	EBB-GTAP*	AEZ-EF	18.65
Use Purdue Default Price-Yield Value	EBB-GTAP	AEZ-EF	12.84
Include CRP Land Conversions	EBB-GTAP	AEZ-EF	11.97
Use CCLUB Emissions Instead of AEZ-EF Emissions (w/o CRP Conversion)	EBB-GTAP	CCLUB	6.84

* Same model as Purdue model used in 2013 Applied Science paper, but with disaggregation of coarse grains and oilseeds in EU27.

[12] Air Improvement Resource, (S&T)^2 Consultants, Steffen Mueller, UIC, "Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project (GTAP) Model," August 30, 2013, for European Biodiesel Board.

Utilizing the ETL1 and ETL2 values from the Applied Science paper reduces emissions from 23.21 to 21.03 g/MJ. Implementing the improved nesting structure reduces emissions further to 18.65 g/MJ. With more reasonable but still very conservative price-yield value of 0.25, emissions are reduced to 12.84 g/MJ. If CRP land is included in conversions, emissions are reduced to about 12 g/MJ. If CCLUB emissions are used instead of AEZ-EF, emissions are just under 7 g/MJ.

ARB is planning on incorporating irrigation changes in GTAP. We support this effort if done in a reasonable manner. ARB is also planning on incorporating "inaccessible" forest in GTAP. We do not support this effort, since inaccessible forest would not be converted to crops or pasture. It is somewhat ironic that ARB wants to include "inaccessible" forest, but is putting no effort into including extremely accessible cropland/pasture in Canada, the EU27, and other regions.

Summary

Overall, ARB's currently analysis of LUC for biofuels in the US has improved from earlier 2009 estimates, but clearly is using modeling inputs that are wrong (price-yield range and ETL1/ETL2 values) and have been proven to be inappropriate, and is also not using certain critical updates to GTAP (i.e., the updated nesting structure) that have been available for awhile. If the ARB analysis were updated appropriately, LUC emissions for corn ethanol would be in the 8-12 g/MJ range. There would be corresponding changes in the LUC emissions of other biofuels as well.

EXHIBIT E to Declaration of James M. Lyons

Low Carbon Fuel Standard Re-Adoption Concept Paper

I. Introduction

Transportation fuels play a key role in California's economic success as well as the lifestyle of its residents. Traditional fuels, like gasoline and diesel, will continue to play a role in supporting California's transportation needs for many years to come. At the same time, the production and use of traditional fuels is responsible for nearly half of the state's greenhouse gas emissions. The Low Carbon Fuel Standard (LCFS) is a key part of a comprehensive set of programs in California to cut greenhouse gas emissions and other smog-forming and toxic air pollutants by improving vehicle technology, reducing fuel consumption, and increasing transportation mobility options. The LCFS is designed to decrease the carbon intensity of California's transportation pool and provide an increasing range of low-carbon and renewable alternatives. This paper includes a set of options for consideration to strengthen the LCFS in achieving this objective.

The California Air Resources Board (ARB/Board) approved the LCFS regulation in 2009 to reduce greenhouse gas (GHG) emissions by achieving a ten percent reduction in the carbon intensity of transportation fuels used in California by 2020. Carbon intensity (CI) is a measure of the GHG emissions associated with the various production, distribution, and consumption steps in the "life cycle" of a transportation fuel. The LCFS is designed to reduce GHG emissions by encouraging the use of low-carbon fuels in California and their production in California and elsewhere. The LCFS is performance-based and fuel-neutral, allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced. ARB approved some amendments to the LCFS in December 2011, which became effective on November 26, 2012, and were implemented by ARB on January 1, 2013. The current and complete regulatory text is available at http://www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder_112612.pdf.

On July 15, 2013, the State of California Court of Appeal, Fifth Appellate District (Court) issued its opinion in *POET, LLC versus California Air Resources Board* (2013) 218 Cal.App.4th 681. The Court held that the LCFS would remain in effect and that ARB can continue to implement and enforce the 2013 regulatory standards while it takes steps to cure California Environmental Quality Act and Administrative Procedure Act issues associated with the original adoption of the regulation. To address the ruling and provide lasting market certainty, ARB staff is proposing that the Board re-adopt the LCFS regulation in 2014. Additionally, ARB staff is proposing a suite of amendments to provide a stronger signal for investments in and production of the cleanest fuels, offer additional flexibility, update critical technical information, and provide for improved efficiency and enforcement of the regulation.

It has been nearly five years since the Board's original action, and the core principles and policies of the LCFS regulation remain valid. The basic framework of the current LCFS, including the use of life cycle analysis, the LCFS credit market, and the LCFS Reporting Tool (LRT), among other aspects, are working and will continue. This

concept paper provides an overview of new elements being considered as part of the 2014 LCFS rulemaking effort. The concepts being considered reflect a range of potential changes, including straightforward updates to the regulation to more significant proposals for improving its overall effectiveness and long-term ability to support the production of increasingly lower-carbon fuels. The concepts will be discussed during a public process over the next several months. Based on stakeholder input, we may make adjustments to the proposals in this paper or recommend alternatives should they be determined to be more effective at realizing the objectives.

II. Status of the LCFS

Since the regulation went into effect, regulated parties have successfully operated under the LCFS program. In short, the LCFS is working as designed and intended. Regulated parties as a whole continue to over-comply with the regulation, providing significant "excess" credits that can be used for future compliance. The requirements (i.e., one percent reduction in CI) are modest at this stage; staff believes that the current developments on clean fuels support compliance for years to come but recognize increasingly larger volumes of low-CI fuels will be needed to meet the targets as we approach 2020. Credits have been generated primarily from ethanol (62 percent), but also from renewable diesel (15 percent), biodiesel (12 percent), and from natural gas (9 percent). Approximately 270 LCFS credits transactions were recorded through February 2014, demonstrating a robust credit market. The LCFS credit prices, which started at $10 to $15/metric ton (MT) CO_2e, have risen to $50 to $85/MT CO_2e.

Further, fuel producers are innovating and achieving significant reductions in the carbon intensities of their fuel pathways, an effect the LCFS regulation is expressly designed to encourage. So far, over 200 innovative fuel pathways (Method 2A/2B applications) have been reviewed and posted by staff.[1]

III. Timeline and Process

Staff will conduct an initial public workshop on March 11, 2014, to discuss potential amendments to the LCFS for 2014 and receive feedback from stakeholders. Other public workshops will be scheduled following the initial public workshop. Staff is also willing to meet with interested stakeholders to discuss staff's proposal via conference calls and one-on-one meetings. Staff will propose a comprehensive LCFS package to the Board in the fall of 2014.

IV. LCFS Re-adoption

Although implementation of the LCFS has gone smoothly, there are opportunities to improve the regulation. Staff had planned to propose amendments to the Board in October 2013 and again in 2014, but in light of the lawsuit, staff determined it would be most efficient to consolidate amendments and return to the Board once in 2014.

[1] See http://www.arb.ca.gov/fuels/lcfs/122310lcfs-rep-adv.pdf.

Therefore, many of the proposed revisions have already been identified and discussed in workshops with stakeholders. These proposed amendments will now be part of the consolidated regulation re-adoption package that responds to the Court's decision.

a. Rationale for Amendments

There are several factors driving the staff's proposed amendments. First, based on stakeholder comments received in both the original 2009 rulemaking and 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. These include updates to the electricity provisions, developing low-energy-use refinery provisions, evaluating a refinery-specific incremental deficit option, and approval of additional fuel pathways.

Second, staff has received feedback from regulated parties and other stakeholders throughout the implementation of the LCFS. This feedback informed the staff's refinements contained in this proposal, such as incentives for petroleum refinery modernization projects and updates to the indirect land use change (iLUC) values.

Finally, staff conducted internal reviews of lessons learned and has been assessing what has changed since the initial implementation of the LCFS. As part of this ongoing assessment, several broad themes have emerged. These include a need to consider developing a compliance schedule that goes beyond 2020 in order to meet California's long-term climate goals. It is also clear that the LCFS would benefit from a greater focus on the long-term goal of ultra-low CI fuels to ensure the long-term effectiveness of the program, and some of the changes below reflect this emphasis. In addition, it is evident that certain aspects of implementing and improving the LCFS regulation, such as evaluating fuel pathways and improving iLUC values, are very resource intensive. In response, some modest changes may allow greater "bang for the buck" and provide additional resources to be put toward greater enforcement, consideration of significant innovations in the fuels sector, and ensuring accountability. Staff is interested in feedback on the proposed concepts and amendments outlined below, but staff is also interested in additional ideas to achieve the policy objectives of the LCFS and the themes described above.

b. New Concepts Being Considered

The following four concepts are being introduced for feedback:

<u>GHG Emissions Reductions at Refineries</u>

ARB is proposing to allow refineries to generate credits for investments at the refinery that reduce GHG emissions. This provision is consistent with full life cycle analyses, but instead of reducing the CI of the fuels produced—as is done with biofuel production facilities—the CI for CARBOB and CARB diesel will remain the same for market fungibility purposes, so credits will need to be the mechanism for recognizing GHG

emission reductions at the refineries. These investments would also reduce associated toxic and criteria air pollutants. Refineries would submit a project plan to ARB for approval and staff would determine the difference between the refinery's baseline CI of their transportation fuel and the new CI of their transportation fuels with the project in place. The difference will be used to calculate credits for the refinery. These credits would be eligible for sale to other regulated parties.

Each refinery that generates a Refinery Investment Credit will have the CI of its transportation fuel reviewed periodically to ensure that the calculated difference has remained the same. Changes in the CI could result in an increase, decrease, or elimination of the credit in future years.

Modification of Compliance Curves for Gasoline and Diesel Standards

Staff is anticipating the rulemaking process for re-adoption of the LCFS to be concluded in 2015. This will likely keep LCFS regulatory standards at 2013 levels through 2015. Staff currently has no proposal to change the average carbon intensity target of 10 percent by 2020; however, staff believes that some post-2015 "curve-smoothing" will be appropriate. Staff is conducting an in-depth analysis of projected fuel availability that will inform the 2016 - 2020 compliance targets.

Achieving the GHG and air quality goals outlined in the draft Scoping Plan Update will require a renewable portfolio of transportation fuels well beyond the current policy trajectories. Accordingly, in 2014 ARB will consider revising the LCFS with post-2020 targets that call for CI reductions greater than 10 percent. This additional analysis will also include the effects of proposed changes to the LCFS, such as potential revisions to the calculation of ILUC values, options for refineries to generate credits via a refinery credit provisions, provisions for electricity credits for off-road applications, and a cost containment provision, which may affect the volumes and types of fuels needed for compliance.

Over the past several years, some stakeholders have raised concerns regarding the availability of low-CI fuels in quantities sufficient for compliance in future years. While staff disagrees with many of the fundamental assumptions leading to these concerns, we believe it is important to draw on the most up-to-date information to assess if there is sufficient progress towards meeting the regulation's future carbon intensity reduction targets. As a result, ARB is analyzing what low-CI fuels are likely to be available for compliance by 2020 as well as the 2030 timeframe, based on industry, academic, and government sources. Staff is developing low-CI fuel projections that take into account the effect of petroleum prices on the production of biofuels which will result in low, medium, and high projections. Staff is also in the process of identifying which of these fuels are likely to come to California to be used for compliance with the LCFS, based on the demand-pull incentive structure of the program (i.e., lowest-cost compliance). ARB staff will continue to work on the analysis as it will help to inform any appropriate regulatory improvements.

Refinery-Specific Crude Oil Incremental Deficit Accounting

Based on the fact that smaller refineries can be affected by the California Average crude oil incremental deficit, but cannot affect the Annual Crude Average carbon intensity, ARB is proposing to allow low-complexity/low-energy-use refineries to opt out of the California Average Crude Provision in the current LCFS regulation and instead have their crude oil incremental deficit calculated on a refinery-specific basis. The large, complex refineries would continue to operate under the California Average crude oil provision.

The low-complexity/low-energy-use refineries would be allowed a one-time, irreversible opportunity to opt for refinery-specific accounting. Interested refineries would have an incremental deficit assessed if their refinery Annual Crude Carbon Intensity exceeds their refinery 2010 Baseline Crude Carbon Intensity. Participating refineries would also be required to:

- Work with staff to properly characterize all crudes supplied to the refinery;
- Provide detailed descriptions, sources, and volumes of refinery intermediate feedstocks and petroleum-based blendstocks that are supplied to the refinery; and
- Provide sources and volumes of finished products supplied by outside refineries.

These additional requirements will help to ensure accurate accounting of crude oil carbon intensity for these low volume refineries.

Fuel Pathways and Producer Facility Registration

LCFS 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 response to those concerns, as well as to the need to focus the program on the promotion of innovation, staff proposes to restructure the certification and registration functions. We are 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, while next-generation fuels, such as cellulosic alcohols, would fall into the second tier. Any fuel (first or next generation) produced using an innovative method, such as carbon capture and sequestration, would fall into the second tier.

Producers of first-tier fuels would be registered into CI bins using an application process that is similar to the existing Method 2 process. The bins would consist of simple carbon intensity ranges. The CI of all fuels in a given bin would be the midpoint of the range that defines that bin. The same registration process fuel providers would use to obtain a first-time tier-one CI would be used to move from one bin to another. This

single, uniform tier-one registration process would replace the existing Methods 1, 2A, and 2B processes.

Producers of second-tier fuels would apply for fuel pathways using a modified version of the existing Method 2 process. Staff would also have the ability to develop and post tier-two pathways for the use of qualifying fuel providers.

When the new LCFS regulation goes into effect, staff would classify all pathways in use at that time into either tier one or tier two. If the new regulation contains provisions requiring that existing CIs be recalculated, those recalculations would have to be completed and approved by staff before the existing pathways could be registered into the new system.

Staff also proposes to adopt a new model for calculating life cycle CIs under the LCFS. That new model would most likely be based upon one of two current versions of the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) spreadsheet from Argonne National Laboratory. One is the latest spreadsheet version of the model, and the other is the new non-spreadsheet version of the model, GREET.net

Details of the staff proposal along with a discussion of alternative approaches considered are presented in Appendix A.

c. Proposed Amendments from 2013

In addition to the above proposals, a number of proposals have already been workshopped and discussed with stakeholders in 2013. Staff is reintroducing these proposals along with our current recommendations.

Cost Containment Provision

Staff proposes the creation of a cost containment provision that would increase market certainty about the maximum costs of compliance, strengthen incentives to invest in and produce low-CI fuels, and provide additional compliance options. Staff drafted a white paper on LCFS cost containment ideas in 2013 and discussed the concept at a May 24, 2013, workshop. Staff is continuing to evaluate the following two options from that white paper but remain open to alternatives that more effectively achieve the same objectives:

1. Credit Clearance Option

Under the credit clearance option, regulated parties would be allowed to carry over deficits to the next compliance period, provided that they purchase their *pro rata* share of all credits made available for sale during a "credit clearance" period. Credit clearance periods would occur at the end of compliance years in which some regulated parties are

unable to obtain the credits on the open market that are required for compliance. At the beginning of the credit clearance period, regulated parties with excess credits would be asked to pledge any credits that they would like to sell at or below a pre-determined price ceiling. Deficit-holding regulated parties' pro rata share would then be calculated based on the size of each party's deficit, and the total number of credits pledged by sellers. Once a regulated party purchases its pro rata share of credits, it would be able to carry its remaining deficit over into the following compliance year. Deficits that are carried over would become part of that regulated party's cumulative compliance obligation and incur interest, to be repaid in subsequent compliance years.

2. Credit Window Option

Under a credit window concept, compliance-only credits would be available for purchase from ARB at a pre-determined price if regulated parties are unable to obtain sufficient credits on the open market. The proceeds from the sale of LCFS credits would go into the Air Pollution Control Fund, unless directed by the Legislature to expend the funds in some other manner.

Staff is evaluating these two options for their potential to:

- Send a strong and transparent market signal to investors regarding the value of low-CI fuels;
- Provide additional options for economical paths to compliance; and
- Minimize the potential for unintended, negative market consequences.

The credit clearance option is the preferred approach because it ensures that credit shortages or price spikes do not destabilize the LCFS credit market, and it strengthens the incentives to invest in low-CI fuels by providing a strong and transparent price signal. The credit clearance option also minimizes the potential for unintended negative market consequences, and enables conventional fuel suppliers to comply with the program without paying for credits or fuels that the market has failed to produce.

Revised iLUC Values

Indirect Land Use Change values for corn ethanol, sugarcane ethanol, and soy biodiesel were included in the LCFS when the Board approved it in 2009 and 2010. Published literature and knowledge in this area has continued to evolve. The Board directed staff to refine the iLUC analysis, taking into account advancements in methodology, data, and scientific understanding.

Based on recommendations provided by an Expert Working Group (EWG, established per the Board's directive) and other stakeholders, staff contracted with experts to refine and improve the iLUC analysis. Accordingly, staff, working cooperatively with the academic researchers, has incorporated significant changes in the estimation of iLUC for biofuels. In addition, a new carbon emission factor model was developed to provide

better estimates of carbon released upon land conversion. Updates to the GTAP[2] model include the addition of data and parameters to estimate iLUC for two new biofuels (canola biodiesel and sorghum ethanol), and necessary refinements in methodology and structure to address recommendations of the EWG and stakeholders. Staff contracted with experts and performed uncertainty evaluations using the Monte Carlo analysis. Staff is also proposing to include impacts related to irrigation and forestry sector into the iLUC analysis in the near-term.

Preliminary results indicate reductions in the iLUC values for soy biodiesel, sugarcane ethanol, and corn ethanol. Staff is proposing to present the results at the March 11 workshop to solicit feedback from stakeholders. Details of the staff draft proposal are presented in Appendix B.

Electricity Provisions

Staff has worked with stakeholders to develop a proposal to add electricity used in fixed guideway systems and electric forklifts to the regulation as eligible to generate credits. The addition of electricity credits would provide greater compliance flexibility to the regulation and be consistent with the objective of promoting low carbon fuel alternatives in a broader spectrum of technologies. Staff held meetings of the LCFS Electricity Workgroup in November 2012 and January 2013 to discuss these concepts. Staff presented the results of the analysis at a public workshop in April 2013 and recommended the proposed concepts at a public workshop in May 2013.

Details of the staff proposal along with a discussion of alternative approaches considered are presented in Appendix C.

Low-Energy-Use Refinery Provisions

On December 16, 2011, the Board directed staff in Resolution 11-39 to consider provisions to the LCFS to address low-energy-use refining processes. This Resolution language was meant to address concerns from refineries that use simple processes to refine transportation fuels to account for the low energy inherently embedded into their fuels. ARB staff investigated the complexity of each California refinery using the Nelson Complexity Score as well as the total energy use of each refinery. Staff is proposing that in order to be considered low-energy-use, a refinery must have a modified Nelson Complexity score of five or less and that the annual energy usage would have to be five million MMBtu or less. Each refinery would have to comply with both parts of the metric to be considered a low-complexity and low-energy-use refinery.

Staff has been working to quantify the difference in transportation fuel carbon intensities between low-complexity/low-energy use refineries and the complex refineries. Staff is proposing to recognize this CI difference within the LRT.

[2] GTAP stands for Global Trade Analysis Project, a global economic model used by staff to estimate iLUC.

Details of the staff proposal are presented in Appendix D.

Innovative Technologies for Crude Oil Production

Currently, the LCFS has a provision for awarding additional credits to refiners who purchase crude oil produced in an innovative manner that lowers greenhouse gas emissions (i.e., carbon capture and sequestration and solar-generated steam for injection). Responding to stakeholder feedback, staff proposed in a workshop last year to instead award the crude *producers* with the innovative production credit, as this would send a stronger economic signal to the producers who are investing in these technologies. A properly designed provision to reward oil producers for implementing innovative greenhouse gas reduction technologies can provide substantial environmental and economic benefits[3].

Staff will also propose to:

- include biomass-based steam as an innovative technique;
- include onsite solar, wind, and biomass-based electricity as innovative techniques;
- include carbon capture coupled with carbon dioxide enhanced oil recovery as an innovative technique under certain circumstances;
- remove the minimum threshold of 1.0 g/MJ carbon intensity reduction to qualify as an innovative technique; and
- simplify the application process and calculation of innovative method credit for solar steam and solar- or wind-based electricity.

Revisions to OPGEE and Updates to the Crude Lookup Table 8

In March 2013, staff presented draft revisions to the Oil Production Greenhouse Gas Emissions Estimator (OPGEE v1.1 Draft A) and an expanded and updated Crude Oil Lookup Table (Table 8). OPGEE v1.1 Draft A incorporated several small revisions to the model, which were made in response to stakeholder feedback during and following the 2011 amendment process. Based on feedback received on OPGEE v1.1 Draft A, staff is presenting OPGEE v1.1 Draft B and related model documentation for feedback at the workshop on March 11, 2014.

Proposed revisions to Table 8 will include both updated carbon intensity values for listed crudes and expansion of the table to include carbon intensity values for all crudes supplied to California refineries from 2010 to 2013, as well as additional crudes of interest to California refiners. This expanded Lookup Table will list carbon intensity values for over 100 internationally and nationally marketed crudes and nearly 200 California oil fields. Table 8 will also include a limited number of default carbon

[3] A white paper discussing Innovative Technologies for Crude Oil Production will posted at a later date.

intensity values to be used in the event a refinery purchases crude not listed in the table. The default carbon intensity will be used until the crude carbon intensity is included in the table as part of a subsequent update.

Finally, staff is proposing that subsequent revisions to OPGEE and Table 8 occur no more frequently than on a three-year cycle and be considered through an Executive Officer hearing process given the administrative nature of the updates. Updating OPGEE and Table 8 on a three-year cycle rather than annually will provide more certainty to refineries for crude purchases as well as allowing limited staff resources to be redirected to other LCFS tasks.

Enhancements to Reporting and Recordkeeping Requirements

Staff intends to propose several amendments to various reporting requirements under LCFS to provide clarity and tighten the implementation of the program. Staff expects to work with stakeholders to refine the concepts discussed below and identify other appropriate changes. Record retention is another issue that will be addressed in the revised provisions. Staff is proposing to align the record retention requirements applied to the ARB Cap and Trade Program to the LCFS Program.

In order to improve the traceability of fuels to the source, staff is proposing to add a provision that requires reporting of all Transaction Types identified in the regulation, including transactions without obligation transfer. There are other proposed enhancements to the reporting requirements associated with the chain of custody for fuels being produced or imported into the State. Further, to substantiate the validity of companies that register in the LRT as a regulated party, a modified registration process will be identified, enabling ARB staff to do a more thorough pre-registration check of each company.

Staff will also propose enhancements to LCFS Product Transfer Documents (PTDs) to include fuel production facility information. Additionally, it would be required to include a statement on the PTD that clearly identifies that the fuel has been reported under California's LCFS. Once reported in the LCFS, it may not be re-imported and reported a second time for additional credits. Finally, the opt-in/opt-out provisions of the regulation would be modified to enable the opt-out process to be implemented online, replacing the current paper-based process.

Enhancements to LCFS Credit Provisions

Staff intends to propose several amendments to LCFS credit provisions to clarify and tighten the implementation of the program. Some of these provisions were discussed with stakeholders last year. Key elements of the changes being proposed are discussed below.

Staff is proposing to require use of the online LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS) for performing all credit transfers. Although the current regulatory text does not explicitly require use of the online system, it has become the *de facto* standard for recording credit transfers, and staff's proposal would simply formalize this. In addition, staff's proposal will provide details of the automated processes as well as authorization protocols for the use of brokers that represent regulated parties. A hierarchy for how credits are to be retired will also be provided. Finally, a provision to allow voluntary posting of credits available for sale/transfer will be provided to facilitate communication between prospective credit buyers and sellers.

Staff also intends to clarify LCFS requirements pertaining to credit retroactivity. Currently, the regulation does not allow credit retroactivity except under limited circumstances (the physical pathway demonstration provision). Staff believes that there is some merit in allowing for a limited expansion of the retroactivity of credits. For example, limited retroactive credits could be issued to a Method 2 applicant considering specified conditions are met. In those cases where there is retroactive credit generation, to the extent that it is allowed, this will be limited to no greater than the two full quarters immediately prior to the quarter in which retroactive credits are requested by a regulated party.

Other amendments include clarifying language stating that all LCFS credits are to be calculated in the LRT-CBTS. The provisions for placing credits on hold for lack of physical pathway demonstration purposes would be revised to clarify the process and the Credits on Hold process used in the LRT-CBTS to ensure they remain consistent.

Finally, staff proposes to clarify the procedures to address situations where more than one regulated party is claiming LCFS credits for the same volume of fuel. In addition, language to provide ARB Executive Officer authority to retire credits found to be invalid will be added.

Enforcement Provisions

Staff discussed with stakeholders last year preliminary enforcement concepts to be incorporated into the LCFS. The primary goal of this provision is to provide clarity in the enforcement provisions to ensure that penalties are fair and effective at maintaining compliance and deterring noncompliance. Staff expects to work with stakeholders to come up with specific provisions that align with these criteria.

In addition to the above items, staff has identified miscellaneous textual revisions in the LCFS based on stakeholder questions and recommendations. We expect to workshop these through the public process.

APPENDICES

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Appendix A
Fuel Pathways and Producer Facility Registration

This Appendix contains additional information regarding staff's proposal to restructure the fuel pathways and producer facility registration functions.

In this rulemaking, staff proposes to restructure the fuel pathway certification and registration functions to accomplish two important goals:

- To streamline and simplify these two functions; and
- To refocus our efforts on the development and certification of next generation fuels, and on the adoption of innovative production methods in all types of fuel pathways.

In order to achieve these two goals, the certification and registration functions would be restructured to create a two-tiered system. Conventionally produced first generation fuels—starch- and sugar-based ethanol, biodiesel, renewable diesel, natural gas, and electricity—would fall into tier one, while next generation fuels—cellulosic alcohols, biomethane, hydrogen, drop-in fuels, etc.—and innovatively produced first-generation fuels would fall into tier two.

Under the proposed tier one process, fuels will be registered into carbon intensity (CI) bins. Staff will create a series of bins for each tier one fuel using life cycle inventory data obtained from various sources, including existing Method 2 applications. Each bin will consist of a mutually exclusive CI range. The CIs at the top, bottom and midpoint of each bin range will be integers. Tier one CIs will have no decimal places. When a producer registers a tier one fuel pathway, that fuel will be assigned the CI at the middle of the range for the bin into which it falls.

Producers of first-tier fuels would be registered into CI bins using an application process that is similar to the existing Method 2 process. The same registration process fuel providers use to obtain a first-time tier-one CI would be used to move from one bin to another. This single, uniform registration process would replace the existing Methods 1, 2A, and 2B processes now in place for all fuels. Registration application packets will include, but will not be limited to, the following:

1. Energy consumption data covering a full two-year period. All forms of thermal and electrical process energy consumed during this period will be accounted for. This data will normally be in the form of energy purchase invoices or receipts.

2. A comprehensive list of the types and quantities of all chemicals, organisms, and feedstocks used in the production process. Users of atypical chemicals, organisms, or feedstocks (e.g., newly developed enzymes, acids or buffering agents for which staff possess no life cycle inventory data, genetically modified microorganism or feedstock strains, etc.) may be required to submit

life cycle inventory data on those materials in order to determine whether they contribute significantly to a fuel's life cycle carbon intensity.

3. If two or more pathway CIs are being sought based on how co-products are processed, data on the processing of co-products would be required. One such co-product is distiller's grains with solubles (DGS), which is co-produced with corn and sorghum ethanol. DGS may or may not be dried before it is consumed by livestock. Due to the energy used in the drying process, ethanol associated with dry DGS has a higher life cycle CI than ethanol associated with wet DGS. In order to apply for two or more CIs based on co-product processing, the plant must submit third-party-validated, plant-specific data definitively demonstrating the energy use differential between the co-products. Any other relevant life cycle inventory data will also be required. In the absence of such data, the fuel will receive a single CI reflecting its total two-year energy consumption record.

4. Feedstock production information. If the CA-GREET default feedstock production CI is claimed, no additional information would be required. If a lower feedstock production CI is claimed, feedstock-specific life cycle data would be required. If the feedstock is covered by LCFS audit and certification protocols, a lower feedstock production CI would be certified only after the audit and certification protocols have been satisfied.

Tier one fuels produced using qualifying innovative methods would be considered under the tier two process. Use of an innovative method, including but not limited to one of the following, would allow a producer to apply for a producer-specific CI under the tier two process:

1. Use of one or more low-CI process energy sources. In order to qualify as an innovative, low-CI energy source, energy from that source must be directly consumed in the production process. No indirect accounting mechanisms, such as the use of renewable energy certificates, can be used to reduce an energy source's CI. Innovative, low-CI energy sources include, but are not limited to, the following:

    a. Biogas or biomethane;

    b. Waste (as defined below) or residual[4] biomass;

    c. Renewable electricity from a dedicated (non-grid) form of generation

        i. Wind turbines,

[4] Residual biomass consists of agricultural, forest, or other types of residues. To qualify for consideration under the tier two process, such residues will have to be certified as having been sustainably harvested.

ii. Photovoltaic arrays,

iii. Fuel cells using a renewably-produced fuel (e.g., biomethane or hydrogen produced from biomethane or from solar-powered electrolysis);

2. Carbon Capture and Sequestration; and

3. A production process innovation that results in a significant decrease in CI.

Fuels would be required to register under the tier one process unless:

1. They are produced using one or more innovative methods such as those described above; and

2. Their CI is below a tier-two threshold CI, to be established by the Executive Officer. Thresholds would be specific to fuel families (e.g., sugar-based ethanol, tallow-based biodiesel, etc.)

The fuels that would be required to register under the tier one process (absent the innovative methods discussed above) include, but are not limited to:

1. Ethanol produced from starch and sugar crops (corn, grain sorghum, sweet sorghum, sugar cane, etc.);

2. Biodiesel produced from used cooking oil, tallow, corn oil, soy oil, canola oil, or camelina oil. Biodiesel produced from other feedstocks that are substantially similar those in this list would also be required to register under the tier one process.

3. Renewable diesel produced from cooking oil, tallow, corn oil, soy oil, canola oil, or camelina oil. Renewable diesel produced from other feedstocks that are substantially similar to those in this list would also be required to register under the tier one process.

4. Fossil-natural-gas-based CNG, LNG, and L-CNG[5]; and

5. Grid electricity used to charge electric vehicles, including plug-in hybrid electric vehicles. The use of renewable energy certificate or other "green portfolio" designations could not be used to reduce the CI of grid electricity. When used to charge battery-electric vehicles, electricity from dedicated, low-CI, off-grid sources would qualify as a tier two fuel.

[5] L-CNG is LNG that is vaporized and then compressed into (and dispensed as) CNG.

When the new LCFS regulation goes into effect, staff would classify all Method 2 pathways in use at that time into either tier one or tier two. If the new regulation contains provisions requiring that existing CIs be recalculated, those recalculations would have to be completed and approved by staff before the existing pathways could registered into the new system. Recalculating and registering the existing pathways into tier-one bins is expected to take some time. Staff proposes establishing a three-to-six-month registration phase-in period to accomplish this task.

The Method 2 process to which tier two fuels would be subject would be a more intensive version of the tier one registration process just described. Although the same basic categories of pathway information would be required under both processes, staff is relatively unfamiliar with the life cycles of tier two fuels. Life cycle inventory data covering tier two pathways may, if it exists at all, be of questionable applicability to the specific Method 2 applications staff is evaluating. Staff will need to work with applicants to verify the data that applicants submit. Verification through third-party audits may be necessary in some cases. These audits may be performed in connection with the enforcement and quality assurance provisions discussed elsewhere in this document.

Compared to the existing Method 2 certification process, therefore, the proposed tier 2 process will require applicants to provide more and higher quality data. Data quality will be largely a function of how well that data has been verified. Applicants should be prepared to provide independent, third-party verification of the data they submit. Increased data *quantity* requirements will be met either through the submission of verified data sets from sophisticated plant data-logging systems, or by similarly verified empirical data gathered through fully controlled in-plant experimental testing. Given the increasing value of the low-carbon fuels falling into the second tier, investments in data collection and verification will more than pay for themselves through the premiums these fuels will command in the market and the credits they will earn.

In order to ensure that all material and energy inputs into the production process are fully and completely accounted for under the tier-two application process, staff will develop clear guidelines covering input accounting. These guidelines will specify that no input can be designated as a "waste" unless its current and foreseeable future alternative fate is final disposal. Final disposal is defined as either landfilling or destruction (through, e.g., incineration). The CIs of inputs that receive "waste" designations under the LCFS will include only the transportation, conveyance, handling, and processing steps to which those inputs are subject. Waste inputs would inherit no CI increment from the processes that originally generated them. As energy and other markets diversify over time, however, fewer and fewer materials and energy sources are sent to final disposal. As a result, staff will require extensive, thorough, and third-party-verified data before granting a "waste" designation to any input.

Most Inputs that are not designated as wastes, will inherit their share of the CI associated with the processes that generated them. Fuel pathways in which steam from other, unrelated processes (e.g., power plants) is used, for example, will inherit the full CI from the process that generated that steam (e.g., a natural gas boiler).

Some inputs may receive "low-value byproduct" designations. Although these inputs are not wastes, the markets into which they are sold (when they are not used as fuel production inputs) are limited, and the market prices they receive are low. An example is molasses from sugar production in Indonesia. This substance has traditionally been used as a low-value poultry feed supplement. Its value is too low to allow it to be profitably exported. When this substance is diverted into ethanol production, it must come into that process with a non-zero CI. Given its low-value byproduct status, however, it should not inherit its full share of the GHG emissions from the production of sugar. It should, instead, receive the CI of the product that replaces it in the poultry feed market after it is diverted into ethanol production. This "displacement" method will be the preferred approach to account for low-value byproducts used as fuel production inputs.

Staff also proposes to adopt a new model for calculating life cycle CIs under the LCFS. That new model would most likely be based upon one of two current versions of the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) spreadsheet from Argonne National Laboratory. One is the latest spreadsheet version of the model, and the other is the new non-spreadsheet version of the model, GREET.net

Appendix B
Revised Indirect Land Use Change Values

This Appendix contains additional information regarding staff's proposal to the revised indirect land use change (iLUC) values.

Chapter IV and Appendix C of the original LCFS Initial Statement Of Reasons (March 5, 2009) provide an overview of the concept of iLUC, methodology used in performing the iLUC modeling, results and discussion of the iLUC effects, and a brief discussion of ongoing analysis and uncertainties in the iLUC estimates. This material provides the basis for comparing the changes to the iLUC analysis to be discussed in this section. Topics covered include the LCFS Expert Working Group (EWG) and recommendations made by its subgroups and independent experts, updates to the iLUC analysis included in this round of modeling revisions, and potential longer-term model updates to be addressed in the future.

In Resolution 09-31, the Board directed the Executive Officer to convene an Expert Working Group (EWG) to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. This workgroup was tasked with evaluating factors that might impact the land use values for biofuels, including agricultural yield improvements, co-product credits, land emission factors, yield price elasticity, and other relevant factors. The EWG presented their recommendations in November 2010, which were later summarized in a report to the Board in December 2010. The reports can be accessed at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm

ARB staff conducted a review of recommendations from the EWG and other independent reviewers (who participated in the EWG process) to determine which recommendations were appropriate and set about prioritizing the model revisions. Both ARB staff and its expert consultants received and considered additional input and feedback from stakeholders and subject matter experts after the completion of the EWG process. Specific model and data updates that were incorporated in draft modeling presented in 2011 include:

1) Use of the GTAP 7 database (moving from 2001 to 2004 baseline data)
2) Addition of cropland pasture category in the U.S. and Brazil
3) Re-estimated energy sector demand and supply elasticity values
4) Improved treatment of corn ethanol co-product (DDGS)
5) Improved treatment of soy meal, soy oil, and soy biodiesel
6) Modified structure of the livestock sector
7) Improved method of estimating the productivity of new cropland
8) Adopting a consistent model version and set of model inputs for all biofuel pathways
9) Revised yield response to price
10) Revised demand response to price
11) Increased flexibility of crop switching in response to price signals

12) Incorporation of an endogenous yield adjustment for cropland pasture[6]

Most of the GTAP model and data modifications above are described in detail in the report provided to ARB by its expert consultant, Wallace Tyner of Purdue University.[7]

For the 2009 regulation, the GTAP model used endogenous carbon emission factors (from Woods-Hole) to estimate iLUC by modeling biofuel expansion. These were aggregated and did not conform to the region/agro-ecological zone (AEZ) framework of the GTAP model. In 2010, ARB contracted with researchers to refine the emission factor framework to match the GTAP model and to also update the factors based on current data. The researchers utilizing data sources and methodology from the IPCC, FAO, and other published literature, developed a spatially explicit emission factor model to conform to the GTAP structure of region/AEZ. This model is called the agro-ecological zone emission factor (AEZ-EF) model. The workshop on September 24, 2011, presented details, documents, and the AEZ-EF model.[8,9,10] The results for land conversion from the GTAP model were combined with the corresponding AEZ/Region and land transition type to calculate total carbon emissions. Since 2011, there have been updates to the AEZ-EF model. The changes include:

1) Contributions to carbon emissions from Harvested Wood Products (HWP) was updated in the model using data compiled by Earles et al.[11]
2) Additional modifications to HWP were performed using above-ground live biomass (AGLB) after 30 years in each region.
3) Peat emission factor was updated to 95 Mg CO_2/ha/yr using the ICCT report[12]
4) Added OilPalmCarbonStock based on Winrock update to RFS2 analysis.[13,14]
5) Updated forest biomass carbon, forest area, and forest soil carbon data using latest data from Gibbs et al.[15]

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[6] Taheripour, F., Tyner, W., and Wang, M., August 2011, Global Land Use Changes due to the U.S. Cellulosic Biofuel Program Simulated with the GTAP Model

[7] Tyner, W., September 2011, Interim Report: Calculation of Indirect Land Use Change (ILUC) Values for Low Carbon Fuel Standard (LCFS) Fuel Pathways, posted online at http://www.arb.ca.gov/fuels/lcfs/09142011_iluc_wtreport.pdf

[8] http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings_2011.htm

[9] Gibbs, H., and Yui, S., September 2011. Preliminary Report: New Geographically-Explicit Estimates of Soil and Biomass Carbon Stocks by GTAP Region and AEZ, posted online at http://www.arb.ca.gov/fuels/lcfs/09142011_iluc_hgreport.pdf

[10] Plevin, R., Gibbs, H., Duffy, J., Yui, S. and Yeh, S., September 2011. Preliminary Report: Agro-ecological Zone Emission Factor Model, posted online at http://www.arb.ca.gov/fuels/lcfs/09142011_aez_ef_model_v15.pdf

[11] Earles J. M., Yeh, S., and Skog, K. E., Timing of carbon emissions from global forest clearance, *Nature Climate Change*, 2012; DOI: 10.1038/nclimate1535

[12] Page, S. E., Morrison, R., Malins, C., Hooijer, A., Rieley, J. O., and Jauhiainen, J., Review of Peat Surface Greenhouse Gas Emissions from Oil Palm Plantations in Southeast Asia, White Paper Number 15, September 2011, www.theicct.org

[13] Harris, N., and Grimland, S., 2011a. Spatial Modeling of Future Oil Palm Expansion in Indonesia, 2000 to 2022. Winrock International. Draft report submitted to EPA.

[14] Harris, N., and Grimland, S., 2011b. Spatial Modeling of Future Oil Palm Expansion in Malaysia, 2003 to 2022. Winrock International. Draft report submitted to EPA.

6) Updated IPCC_GRASSLAND_BIOMASS_TABLE with data from Gibbs et al.[16]
7) Other minor changes in the model.

In the 2012-2014 timeframe, staff working with Purdue University added additional biofuel modeling capabilities, made changes to the structural elements, and completed extensive evaluations of certain parameters in the GTAP model. The changes include:

1) Disaggregated sorghum from the coarse grains sector to allow for modeling iLUC impacts for sorghum ethanol;
2) Disaggregated canola (rapeseed) from the oilseeds sector to facilitate modeling of iLUC for canola based biodiesel; and
3) Developed regionalized land transformation elasticities for the model using recent evidence for land transformation.[17]

Parameters and structural elements that were reviewed in detail include:

1) Completed exhaustive review of literature on yield price elasticity;
2) Compared DDGS exports predicted by the model to real-world export data;
3) Reviewed model outputs for biodiesel to study impacts on marginal vegetable oil in the global markets due to 'removal' of vegetable oils for biofuel production;
4) Worked with Purdue to tune regional land transformation elasticities to address land conversion related to managed versus unmanaged forests;
5) Studied impacts of land transformation elasticities on land conversion estimates in general and forestland in particular;
6) Evaluated impacts of varying Armington elasticity on model outputs;
7) Researched Purdue's use of TEM results to develop ETA values; and
8) Investigated time accounting methods including reviewing updated literature articles.

Based on staff review, necessary modifications were made to the model for some of these issues. It was determined that some issues require structural modifications or methodological changes (e.g., use of dynamic version) and will be addressed in the future.

Based on staff assessment of various parameters, methodology, and modeling framework, staff proposed to use a matrix of scenarios by varying values for YDEL[18], ETL1[19], ETL2[20], PAEL[21], and ETA[22]. These parameters were also identified by the

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[15] Gibbs, H., Yui, S., and Plevin, R. J., in review. Improved Estimates of Soil and Biomass Carbon Stocks for Global Economic Models. West Lafayette, Indiana: Purdue University.
[16] Ibid.
[17] Taheripour, F., and Tyner, W. Biofuels and Land Use Change: Applying Recent Evidence to Model estimates, *Appl. Sci.* 2013, *3*, 14-38; doi:10.3390/app3010014
[18] Price yield elasticity
[19] Land transformation elasticity that governs land conversion between forest, cropland, and pasture land
[20] Land transformation elasticity that distributes available cropland between crops
[21] Cropland pasture elasticity

Monte Carlo Analysis as those that contributed the most to variance. Table 1 below provides details of these parameters and the range of values used in the scenario analysis.

Table 1. Parameters and Range of Values Used in Scenario Analysis

Parameter/scenario	Range of values used
YDEL	0.05 to 0.3
ETL1	80% to 120% of baseline
ETL2	80% to 120% of baseline
ETA	80% to 120% of baseline
PAEL_US	0.1 to 0.6
PAEL_Brazil	0.1 to 0.3

Using various combinations of parameter values from above, a total of 1,440 scenario runs was completed for each biofuel. The results are compared to distributions generated using the Monte Carlo analysis.

Several stakeholders had requested that staff perform uncertainty analysis related to iLUC modeling with the GTAP model. The EWG had similar recommendations.[23] To address uncertainty, staff contracted with the University of California, Berkeley (UCB). Researchers at UCB developed a Monte Carlo simulation framework to analyze uncertainty related to iLUC emissions estimated using GTAP and the AEZ-EF models. Using Latin Hypercube sampling to draw values for model inputs, thousands of trials were run to produce frequency distributions for iLUC emissions estimates. Utilizing the same framework, they also identified key parameters that contribute the most to uncertainty in the estimates of iLUC emissions.

[22] Elasticity of crop yields with respect to area expansion
[23] Uncertainty Subgroup, Final Report to LCFS Expert Workgroup, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm

Short-Term and Long-Term Model Updates

Researchers at Purdue University are under contract to explore model changes, some of which were recommended by the EWG. These issues are listed below and some have references made to the EWG subgroup or independent reviewer final report which describes the recommendation in detail:

Short-Term Updates

1) Split crop production into irrigated versus rain-fed and develop datasets and metrics to assess impacts related to water-constraints in agriculture across the world.
2) Continue to update and improve the land pools within GTAP deemed to be accessible for conversion to cropland. Additional land pools may include "inaccessible" forests; unmanaged shrub land, grassland, and savanna; idle/fallow/abandoned cropland; and other marginal (low productivity) lands.[24] Split existing forestland into managed/unmanaged forestry sectors.

Long-Term Updates:

1) Consider a broader range of significant indirect emissions from land use changes such as, but not limited to, those related to fertilizer, livestock and rice production and from crop switching.[25]
2) Consider accounting for the effects of non-Kyoto climate forcing gases and particles (e.g., black carbon) in addition to carbon dioxide, methane, and nitrous oxide.[26]
3) Adopt a modeling framework that allows for the dynamic nature of land use change that can incorporate time dependent changes such as technology driven yield improvements and food demand (influenced by the dynamics of economic and demographic change). This will likely involve switching to a dynamic version of GTAP.[27]
4) Evaluate alternative approaches to calculating yields on new agricultural lands based on statistical analysis of climate and management factors using updated datasets.[28] Estimates of yields on newly converted lands should also factor in economics of land selection.[29]
5) Evaluate alternative approaches to how the model determines which land types (e.g., forest or pasture lands) are converted to cropland. This either involves a

[24] Land Cover Types Subgroup, Final Report to the LCFS Expert Workgroup, November 22, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[25] Carbon Emission Factors Subgroup, Final Report to the LCFS Expert Workgroup, November 19, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[26] Ibid.
[27] Land Cover Types Subgroup, Final Report to the LCFS Expert Workgroup, November 22, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[28] Ibid.
[29] Berry, S., January 4, 2011. Report to ARB: Biofuels Policy and the Empirical Inputs to GTAP Models. Posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm

significant change in model structure or the use of land conversion probabilities for each region of the world which are exogenous to the model. Currently the model estimates both the amount of land converted to crops and the type of land converted. Observed land conversion probabilities could be used to better calibrate the model estimates of type of land converted (i.e., calibrate the CET function parameter on a regional level). Alternatively, the model could be used to predict only the amount of land converted and observed data for land conversion probabilities could be used to estimate the type of land converted.[30,31]

6) Evaluate the use of Armington versus Heckschler-Ohlin structures for modeling international trade. The use of Armington structure for trade in GTAP, although appropriate in the short term, may be unrealistic over the long term. Armington assumptions give greater preference to meeting increased demand with domestic production or from normal trading partners. In contrast, the Heckschler-Ohlin structure assumes similar crops of different origin are nearly perfect substitutes. [32,33]

[30] Ibid.
[31] Elasticity Values Subgroup, Final Report to the LCFS Expert Workgroup, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[32] Berry, S., January 4, 2011. Report to ARB: Biofuels Policy and the Empirical Inputs to GTAP Models. Posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[33] Reilly, J., November 4, 2010, Report to ARB: GTAP-BIO-ADV and Land Use Emissions from Expanded Biofuels Production, Posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm

Appendix C
Electricity Provisions

This Appendix contains additional information regarding staff's proposal to the electricity provisions.

1. Off-Road Categories for Credit Generation

The current regulation allows regulated parties to generate credits for electricity used in on-road vehicles only. However, credit generation could potentially be expanded to electricity used in off-road vehicles. The Board directed staff in Resolutions 09-31 and 11-39 to evaluate the feasibility of issuing credits for non-road electricity-based transportation sources, including mass transit, and propose amendments, if appropriate, to the regulation. As a result, staff has worked with stakeholders to develop a proposal to add electricity used in fixed guideway systems and electric forklifts to the regulation as eligible to generate credits. In considering potential off-road categories to add to the regulation, staff selected fixed guideway systems and electric forklifts as categories of electric transportation that use significant amounts of electricity and have been identified as eligible to voluntarily opt into the LCFS program.

Fixed Guideway Systems

For the purposes of the LCFS regulation, a fixed guideway system is a system of public transit electric vehicles that can operate only on its own guideway constructed specifically for that purpose, such as light rail or heavy rail, exclusive right-of-way bus operations, and trolley coaches. In California, these systems provided lower carbon transportation for over 340 million passenger trips in 2012 (American Public Transportation Association 2013). Providing an opportunity for credit generation for use of electricity as a transportation fuel supports the overall purpose of the LCFS to reduce GHG emissions from the transportation sector, reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of alternative, low-carbon fuels in California.

Staff proposes that transit agencies operating fixed guideway systems be eligible to opt-into the program and become regulated parties, and therefore qualify to generate credits, for electricity used to propel fixed guideway systems. There are six transit agencies in the state reporting electricity use for transit propulsion annually to the National Transit Database (National Transit Database 2012). Staff further proposes to allow Electrical Distribution Utilities (EDUs) to be regulated parties for electricity used for propulsion in fixed guideway systems in their service area if the transit agency is unable or unwilling to participate in the program.

To calculate the number of credits generated for electricity use in fixed guideway systems, the Energy Efficiency Ratio (EER) must first be determined. The EER is the efficiency of the system compared to the efficiency of the mode of transport riders would have taken if the system was not available. EERs are often in units of

fuel energy (MJ)/mile; however, for mass transit it is necessary to take into account the number of passengers riding. Therefore, EERs for fixed guideway systems calculated for the LCFS program are as follows:

EER = annual propulsion energy (MJ)/(total passengers) (total miles traveled)

This method accounts for the fact that transit cars that operate with a full load of passengers are more efficient, in general, than transit cars that carry few passengers. Staff determined EER values for systems compared to both a passenger car and a diesel transit bus. Transit surveys suggest that approximately one-third of passengers would have otherwise taken their trip using a car and one-third would have taken a bus (the remaining one-third gave a variety of answers, including not taking the trip, carpooling, or unknown) (Bay Area Rapid Transit 2012). There is little difference between the two EER values, and staff chose to compare the energy use of the fixed guideway system to the energy use of a diesel bus. Electricity use for transit is available in the National Transit Database program and ridership data is available in the Public Transportation Ridership Report. EER values vary significantly among fixed guideway systems in the state. For this reason, staff is proposing to use the most recent information available to calculate EER values for input into the LCFS Reporting Tool (LRT) for credit calculation. EER values will be updated in the LRT as deemed appropriate.

All of the fixed guideway systems in California operating today were also operating in 2010, the LCFS baseline year. Because the displacement of diesel fuel cannot be attributed to the LCFS for the electricity used on transit lines that were also operating in 2010, staff proposes to use a modified credit formula that does not give credit for diesel fuel displacement. The modified credit formula is:

$$Credits\ (MTCO_2e) = \left(CI_{standard} - CI_{reported}\right) x\ E_{propulsion}\ x\ C$$

where:

$CI_{standard}$ is the carbon intensity requirement of diesel fuel for a given year;
$CI_{reported}$ is the adjusted carbon intensity value of electricity, in gCO_2e/MJ, calculated as per Section 95484(a)(3)(B);
$E_{propulsion}$ is the total amount of energy used for fixed guideway transit propulsion, in MJ; and
$C = 1.0x10^{-6}(MTCO_2e)/(gCO_2e)$

For credits associated with future fixed guideway system expansion that includes extension to existing track, staff proposes to use the credit formula in Section 95485(a)(3) which provides for diesel displacement credit.

Staff estimates that during the 2015-2020 time period, total credit generation for fixed guideway transportation could potentially be as high as 900,000 credits ($MTCO_2e$) if all regulated parties opted into the program and reported all electricity used for propulsion.

Based on an estimated credit value range of $40 to $100, these credits could be valued at $36M to $89M. If all fixed guideway transportation credits were generated and all credits were sold to satisfy program obligations, the impact on the LCFS program could be one percent of the total program GHG reductions.

Electric Forklifts

Nationwide, electric forklifts, including motorized hand trucks, have taken a larger market share than internal combustion engine (ICE) forklifts powered by gasoline, propane, compressed natural gas, or diesel fuel in recent years (Industrial Truck Association 2013). Staff estimates the number of Class 1, 2, and 3 electric forklift shipments to California in 2012 was approximately 11,500 (Industrial Truck Association 2013, U.S. Census Bureau 2013). An increase in electric forklift use coupled with a decrease in ICE forklift use will result in decreased GHG emissions and contribute to meeting the goals of the LCFS program.

Staff proposes that EDUs be the regulated parties, and therefore qualify to generate credits, for electricity used to charge forklifts. Many EDUs are currently submitting quarterly LCFS reports for electricity used in on-road EVs, and could also include forklift electricity use in quarterly submittals.

Many electric forklifts are charged without the use of a dedicated meter to measure electricity use. Facilities often charge batteries used in multiple equipment types using the same charging equipment and meter. In addition, tracking down metered data for thousands of forklifts would likely be cost prohibitive. For these reasons, staff proposes to estimate the amount of electricity used to charge electric forklifts in each utility service area. The number of forklifts used in California and the amount of electricity used by the fleet can be estimated using national shipment data, battery size, assumed annual operating hours and load factor. Further, each utility's share can be approximated based on their share of the state's non-residential (business/commercial) accounts.

It is likely that many of the electric forklifts that are operating in California today were also operating in 2010, the LCFS baseline year. Because the displacement of diesel fuel cannot be attributed to the LCFS for the electricity used in forklifts that were also operating in 2010, staff proposes to use a modified credit formula that does not give credit for diesel fuel displacement. The modified credit formula is:

$$Credits\ (MTCO_2e) = \left(CI_{standard} - CI_{reported}\right) x\ E_{propulsion}\ x\ C$$

where:

$CI_{standard}$ is the carbon intensity requirement of diesel fuel for a given year;
$CI_{reported}$ is the adjusted carbon intensity value of electricity, in gCO_2e/MJ, calculated as per Section 95484(a)(3)(B);
$E_{propulsion}$ is the total amount of energy used for electric forklifts, in MJ; and

$$C = 1.0x10^{-6}(MTCO_2e)/(gCO_2e)$$

Furthermore, staff estimates that during the 2015-2020 time period, total credit generation for electric forklifts could potentially be as high as 200,000 credits ($MTCO_2e$) if all regulated parties opted into the program and reported all electricity used for forklifts. Based on an estimated credit value range of $40 to $100, these credits could be valued at $8M to $20M. If all electric forklift credits were generated and all credits were sold to satisfy program obligations, the impact on the LCFS program could be 0.2 percent of the total program GHG reductions.

Alternative Approaches

Staff considered two alternative approaches to allowing fixed guideway transportation and electric forklifts to participate in the program and generate credits as explained above. The alternatives are 1) to propose no amendments to address credit generation from these sources, and 2) to modify the 2010 LCFS baseline to include alternative fuels.

Simply, the electricity used in fixed-guideway transportation and electric forklifts is a transportation fuel. Therefore, that electricity should be eligible as an opt-in fuel in the LCFS. There are additional benefits for recognizing this electricity under the LCFS. If no action is taken to include fixed guideway transportation and electric forklifts as eligible to generate LCFS credits, the result would be no change in the number of credits that would otherwise be available on the LCFS market. The larger credit pool that would result from additional available credits could hold credit prices at a lower level; conversely, not offering a credit opportunity for fixed guideway transportation and electric forklifts would remove this potential effect on the credit price. Further, the additional revenue from credit sales for transit agencies could result in increased ridership due to added transit lines, stops, or public outreach efforts. Higher fixed rail ridership could result in additional displacement of gasoline and diesel fuel use, thereby improving air quality as well as providing additional GHG emission benefits. Credit revenue from electric forklift use may be used to educate fleet operators on the benefits of electric forklifts or to provide lower electricity rates to fleet operators. Such benefits would not be realized if no action is taken.

The second alternative considered by staff involves modifying the 2010 baseline to include alternative fuel use. In this analysis, staff first determined the fuel use of transit and non-transit natural gas, transit electricity and electric forklifts in 2010. Next the carbon intensity of these fuels was incorporated into the 2010 diesel standard based on each fuel's portion of the total fuel pool (diesel and diesel replacements). A revised diesel standard was determined, and corresponding annual standards calculated, to reflect the revision. Including alternative fuel use in the baseline lowers the 2010 diesel standard by approximately 2 gCO_2e/MJ and subsequent standards for 2015-2020 by approximately 1 gCO_2e/MJ. This standard adjustment would increase diesel deficits and decrease alternative fuel credits compared to the current program. Staff presented the results of this analysis at a public workshop in April 2013 and thereafter considered

stakeholder feedback. Staff chose not to pursue the baseline approach because compliance with the diesel standard would become more difficult with no corresponding benefit to the alternative fuel market. In addition, because these credits would be generated only if regulated parties opt-in to the program and report electricity use, a change to standards based on potential credit generation would be unfair to diesel regulated parties. This recommendation was subsequently presented at a public workshop in May 2013.

2. Modification of Requirement for all Electricity Reporting to be Metered Data

Staff is proposing to modify the requirement that all reporting of electricity used in residential EV charging after January 1, 2015, is based on direct metering. The modification would allow for an approved electricity estimation method to be used, where metered data was not available, after January 1, 2015. To date, many EV drivers have elected not to install direct EV metering at their residences. Therefore, a provision has been included in the regulation to allow regulated parties to, upon Executive Officer approval, use an estimation method to approximate residential EV charging electricity.

The estimation method currently being used by some utilities[34] is based on all available directly metered data in each utility's service territory and California Department of Motor Vehicles registration data. The number of credits generated through an estimation method is not expected to differ significantly from the number of credits generated solely through the reporting of metered data (if all EV drivers employed direct metering to measure their charging electricity).

Staff considered the no action alternative to the staff proposal. No modification to the metering requirement would significantly decrease the number of available credits in the market and likely increase the cost of complying for those needing to purchase credits. For this reason, staff believes that an amendment is necessary to continue providing credit generation opportunity from estimated electricity use.

[34] http://www.arb.ca.gov/fuels/lcfs/workgroups/elect/04122013-caletc-letter.pdf

Appendix D
Low-Complexity/Low-Energy-Use Refinery Provisions

This Appendix contains additional information regarding staff's proposal to the low-complexity/low-energy-use refinery provisions.

On December 16, 2011, the Board directed staff in Resolution 11-39 to consider provisions to the LCFS to address low-energy-use refining processes. This Resolution language was meant to address concerns from refineries that use simple processes to refine transportation fuels to account for the low energy inherently embedded into their fuels. ARB staff investigated the complexity of each California refinery using the Nelson Complexity Score as well as the total energy use of each refinery.

1. Modified Nelson Complexity Score

The Nelson Complexity Score was first developed in 1960 by W. L. Nelson. It is a metric that compares the cost of a process unit as compared to a distillation unit. The relative capacity of each unit as compared to the distillation unit is used to calculate the overall complexity of the refinery (Nelson, 1976). For example, one barrel of crude is sent through the distillation unit, but only a fraction of that barrel is sent through the subsequent "downstream" processing units. Each fraction is multiplied by the complexity index for each process unit and then summed. That sum is the complexity of the refinery.

The complexity of California refineries was calculated using the 2010 World Wide Refining Survey (OGJ, 2010). This survey included updated Nelson Complexity factors as well as process unit capacities. Since the LCFS deals with transportation fuels, the Nelson Complexity Score was modified to exclude asphalt and lube oil production. Equation 1 shows the calculation for the modified Nelson Complexity Score. Table 1 contains all the indices.

$$Modified\ Nelson\ Complexity\ Score\ = \sum_i^n (index_i) \left(\frac{Capacity_i}{Capacity_{dist}}\right) \qquad \text{Eq. 1}$$

where:

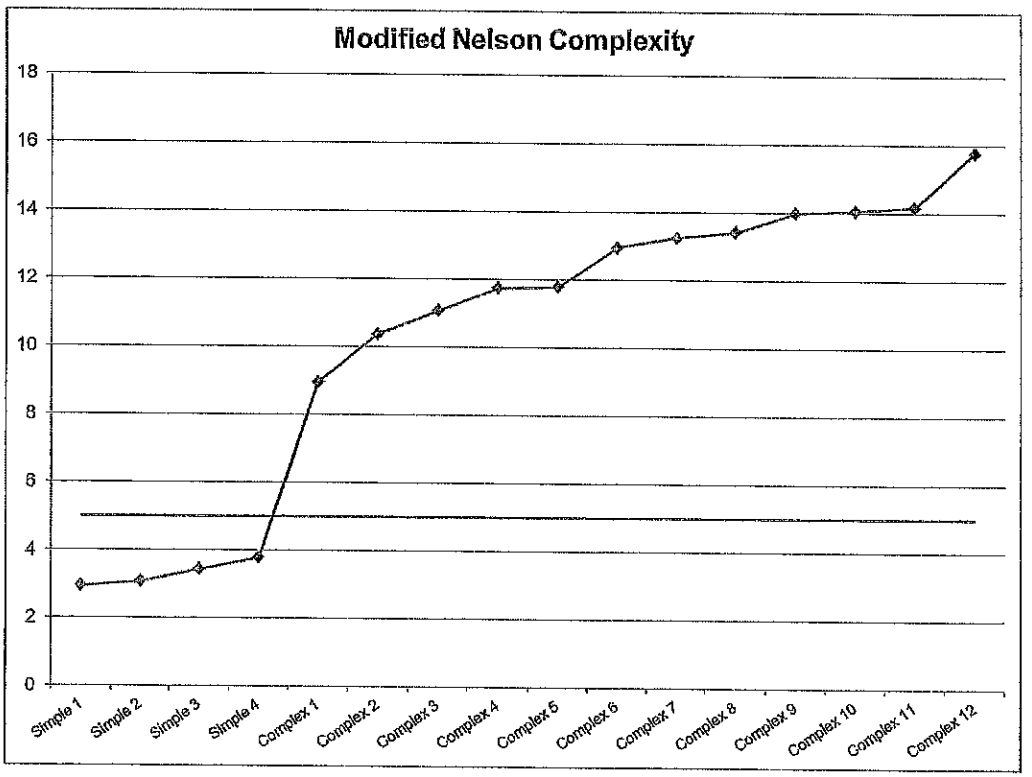
$index_i$ = 2012 Nelson Complexity Index listed in Table 1;
$Capacity_i$ = capacity of each unit listed in Table 1;
$Capacity_{dist}$ = capacity of distillation unit;
i = process unit; and
n = total number of process units.

Table 1. Nelson Complexity Indices.

Process Unit	*Index Value*
Vacuum Distillation	1.30
Thermal Processes	2.75
Delayed and Fluid Coking	7.50
Catalytic Cracking	6.00
Catalytic Reforming	5.00
Catalytic Hydrocracking	8.00
Catalytic Hydrorefining/Hydrotreating	2.50
Alkylation	10.00
Polymerization	10.00
Aromatics	20.00
Isomerization	3.00
Oxygenates	10.00
Hydrogen	1.00
Sulfur Extraction	240.00

Figure 1 shows the modified Nelson Complexity Score for each refinery supplying transportation fuel to California. Four refineries have modified Nelson Complexity Scores between 2 and 4 and twelve refineries have modified Nelson Complexity Scores between 9 and 16. Figure 1 illustrates a very clean break between "simple" refineries and "complex" refineries. Staff is proposing that a modified Nelson Complexity Score of 5 or less constitutes a low-complexity refinery.

Figure 1: Modified Nelson Complexity Scores



2. Total Energy Use

The total energy use of each refinery supplying transportation fuel to California was calculated using direct combustion, imported electricity and steam, and exported electricity and steam reported in the Mandatory Reporting Regulation. Equation 2 illustrates the calculation to determine each refinery's total annual energy use.

$$Energy\ Use\ (MMBtu/year) = fuel\ use + electricity + thermal \qquad \text{Eq. 2}$$

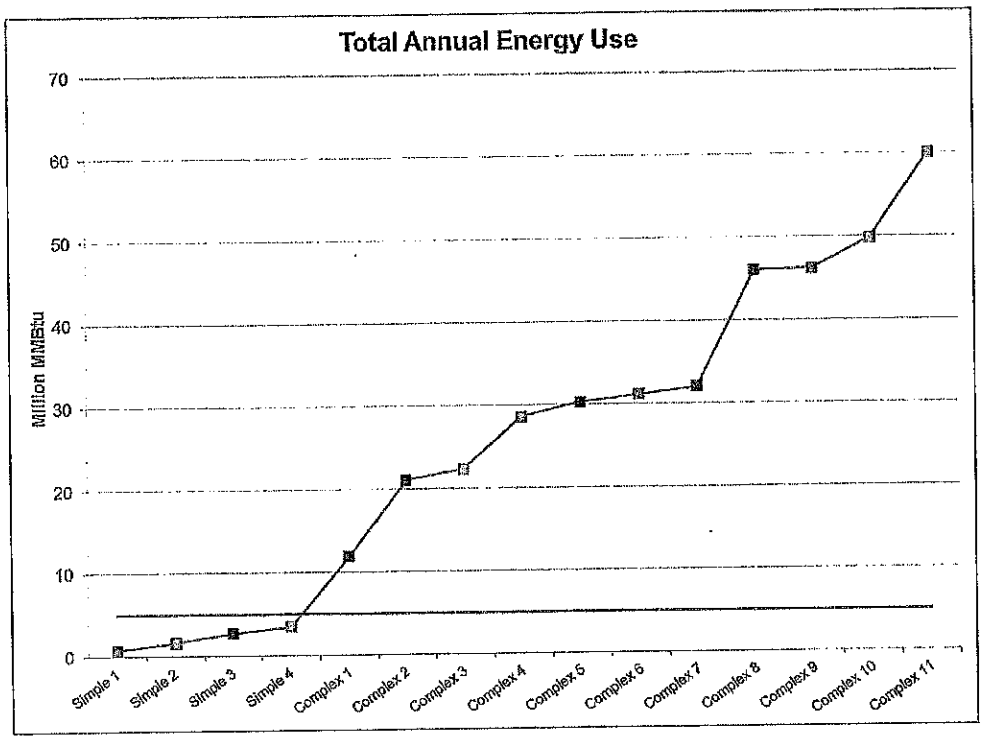
where:

$fuel\ use$ = MMBtu of all fuel combusted per year;
$electricity$ = imported electricity minus exported electricity per year converted to MMBtu by using 3.142 MMBtu/MWh; and
$thermal$ = imported thermal energy minus exported thermal energy per year in MMBtu.

Four years of energy use data (2008 – 2011) were used to compute an average of the annual energy used by each refinery. Figure 2 shows the annual energy use of each refinery supplying transportation fuel to California. This graph shows that four refineries use less than 5 million MMBtu of energy per year, one refinery uses about 11 million MMBtu of energy per year, and the remaining refineries use greater than 20 million

MMBtu of energy per year. The four refineries that are below 5 million MMBtu of energy use per year are closely grouped and are the same refineries that are low-complexity refineries. Staff is proposing that a refinery must use 5 million MMBtu or less of energy to be a low-energy-use refinery.

Figure 2: Total Annual Energy Use



3. Proposed Amendments

Staff investigated the actual carbon intensity of the gasoline and diesel produced by low-complexity/low-energy-use refineries using data from 2008 to 2011. Equation 3 apportions emissions from each refinery on a volume basis.

$$CO_2e\ emissions\ (metric\ tons/year)_i = \left(\frac{Volume_i}{Volume_{total}}\right)(CO_2e\ emissions\ (metric\ tons)_{total}) \qquad \text{Eq. 3}$$

where:

$CO_2e\ emissions\ (metric\ tons/year)_i$ = amount of emissions apportioned to each product i output of refinery;
$CO_2e\ emissions\ (metric\ tons)_{total}$ = total emissions;
$Volume_i$ = volume of individual product output in barrels (bbl); and
$Volume_{total}$ = total volume of output product in barrels (bbl).

Each product was converted to total energy content using the Equation 4.

$$Energy\ Content\ (MJ)_i = (Volume_i)\left(energy\ content\ \left(\frac{MJ}{gal}\right)\right)\left(42\ \left(\frac{gal}{bbl}\right)\right) \quad \text{Eq. 4}$$

where:

$Energy\ Content\ (MJ)_i$ = total energy for each product output;
$Volume_i$ = volume of individual product output in barrels (bbl); and
$energy\ content\ \left(\frac{MJ}{gal}\right)$ = total energy content for each type of product.

Lastly, the total apportioned emissions for each product was divided by the total energy content for the volume of product produced. This renders the gCO_2e/MJ for each product.

$$Emissions\ \left(^{g\ CO_2e}/_{MJ}\right) = \left[\frac{CO_2e\ emissions\ (metric\ tons/year)_i}{Energy\ Content\ (MJ)_i}\right]\left(\frac{10^6\ g}{metric\ tons}\right) \quad \text{Eq. 5}$$

Table 2 lists the average carbon intensity for gasoline and diesel. The average gasoline carbon intensity for the low-complexity/low-energy-use refineries is TBD $gCO_2e/$ MJ. The average gasoline carbon intensity for the remaining refineries is TBD gCO_2e/MJ. The CA-GREET carbon intensity for gasoline is 13.72 CO_2e/MJ. The low-complexity/low-energy-use refinery carbon intensity is roughly TBD gCO_2e/MJ below the CA-GREET carbon intensity.

The average diesel carbon intensity for the low-complexity/low-energy-use refineries is TBD $gCO_2e/$ MJ. The average diesel carbon intensity for the remaining refineries is TBD gCO_2e/MJ. The CA-GREET carbon intensity for diesel is 11.41 gCO_2e/MJ. The low-complexity/low-energy-use refinery carbon intensity is roughly TBD gCO_2e/MJ below the CA-GREET carbon intensity for diesel.

Table 2. Gasoline and Diesel Refinery Carbon Intensities.

	CA-GREET (gCO_2e/MJ)	***Low-Complexity/Low-Energy-Use Refineries (gCO_2e/MJ)***	***Complex Refineries (gCO_2e/MJ)***
Gasoline	13.72	TBD	TBD
Diesel	11.41	TBD	TBD

Staff is proposing to recognize this CI difference within the LCFS Reporting Tool.

California Environmental Protection Agency

Air Resources Board

Low Carbon Fuel Standard Proposed Amendments

April 3, 2013

Agenda

- Proposed Draft Regulatory Changes
  - Electricity Credits for Fixed Guideway Transportation and Forklifts
  - LCFS Reporting Tool – Credit Bank and Transfer System
  - Miscellaneous Changes
- Next Steps
- Contact Information

Proposed Draft Regulatory Changes

- Electricity Credits for Fixed Guideway Transportation and Forklifts
- LCFS Reporting Tool – Credit Bank and Transfer System
- Miscellaneous Changes

Electricity Credits Overview

- Staff concept to include fixed guideway transportation and electric forklifts
- Stakeholder requested alternate approach to include alternative fuels in diesel baseline
  - Method
  - Results
- Requirement for residential metering in 2015

Staff Concept to Include Fixed Guideway Transportation and Forklifts in the Regulation

- Board directed staff (Resolution 11-39) to further evaluate feasibility of generating credits for electricity used in nonroad transportation sources
- Staff is considering adding fixed guideway transportation (electric rail) and electric forklifts to the regulation
- Staff has previously presented a concept to allow these sources to generate credits using a modified credit calculation

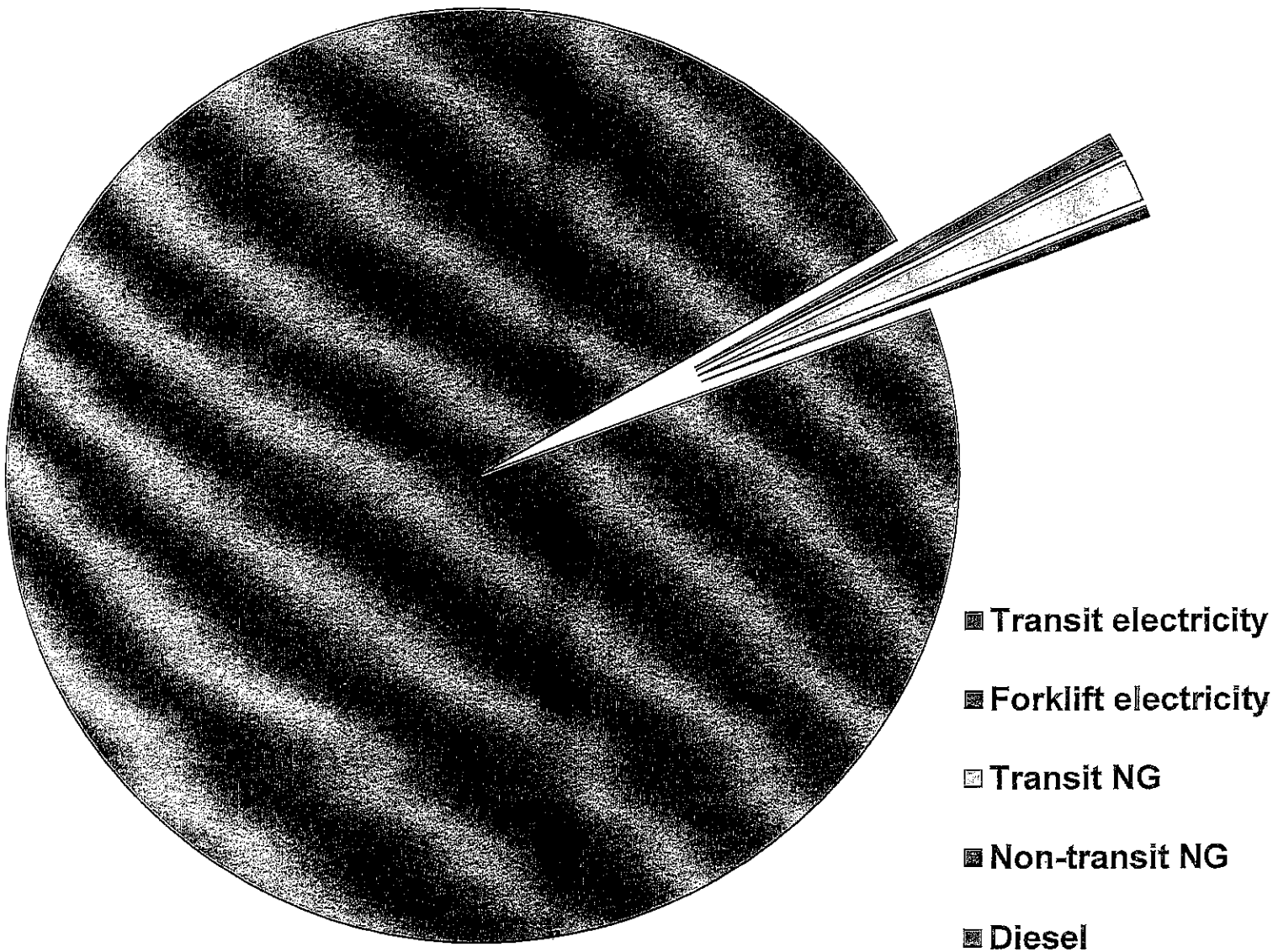
Alternate Approach of Including Alternative Fuels in the Baseline

- Stakeholders requested analysis of an alternate approach
- This approach involves adjusting the 2010 baseline by including 2010 alternative fuels use that is not currently in the baseline
- Fixed guideway transportation and electric forklifts (and other sources) can be added to the 2010 baseline
- This approach adjusts the diesel standard and therefore affects the number of deficits and credits generated

Method to Include Alternative Fuels in the Baseline

- CI of diesel is 98.03 gCO_2e/MJ
- We adjusted the CI to include 2010 fuel use in:
  - Fixed guideway transportation
  - Electric forklifts
  - Transit natural gas
  - Non-transit natural gas
- Other alternative fuel use could be added, but results would not likely change substantially

Magnitude of Fuel Energy Use (MMJ) in Adjusted Diesel Baseline



Results of Including Alternative Fuels in the Baseline

- Including alternative fuels in the baseline
  - reduces the diesel carbon intensity by 1.1 gCO_2e/MJ
  - increases projected annual deficits
- Additional annual deficits on the order of 440,000 MTCO2e/year
- Total fuel pool 2014 deficits increase by 14%
- Total fuel pool 2020 deficits increase by 3%

Results of Including Alternative Fuels in the Baseline

- Staff calculated credits for alternative fuel use under the baseline approach *without* credit for fuel displacement
- Number of potential credits for fixed guideway transportation under the baseline approach decreases by 1.5% from staff's original concept
- Number of potential credits for NG fleet under the baseline approach decreases by 4-5% from staff's original concept

Requirement for Residential Metering in 2015

- Section 95484(b)(3)(C)(1) states that effective January 1, 2015, reporting of electricity dispensed to electric vehicles in residences must be based on direct metering
- Many EVs owners are choosing to charge at residences with no meter
- A robust estimation method has been developed for use by CalETC members
- Staff recommends that the 2015 metering requirement be removed from the regulation

Proposed Draft Regulatory Changes

- Electricity Credits for Fixed Guideway Transportation and Forklifts
- LCFS Reporting Tool – Credit Bank and Transfer System
- Miscellaneous Changes

Credit Bank & Transfer System - Update

Upcoming Release Status – CBTS

- Internal ARB User Testing
  - Credit Transfer System
  - Accomodation of Brokers in CBTS
  - Other new functionality
- External User Testing
  - Credit Transfer System
  - Brokers and Regulated Parties
- Target Date for Completion: 4/17/2013

  Testing w/ system updates

LCFS Credit Bank & Transfer System (CBTS)

- Accommodates Brokers in transfers
- Nine different transfer scenarios
  - Non-Blind (4)
  - Seller-Blind (2)
  - Buyer-Blind (2)
  - Double-Blind (1)
- Identifies Carryback Credits

Other Enhancements

- Total Obligated Volumes

  System Checks that the TOV remains positive

  In operation during quarterly reporting

- Electricity – Annual Reporting

  Enables upload of documents

- Other enhancements
  - Newly Revised User Guide
  - Improved file upload process

Proposed Draft Regulatory Changes

- Electricity Credits for Fixed Guideway Transportation and Forklifts
- LCFS Reporting Tool – Credit Bank and Transfer System
- Miscellaneous Changes

Clarify When Diesel CI Obligation Passes to Buyer

- CARB diesel CI obligation may be passing on to some diesel marketers/distributors (non-blenders)
- Contrary to regulatory intent
- Not a significant problem at this time
- Review section 95484(a)(2)(B)(4 & 5)
- Goal: Address potential issue while allowing CI obligation transfer to those intending to blend further (e.g., for biodiesel/renewable diesel credits)

Energy Density

- Allowing the use of an alternative energy density value

- Revision to Table 4 and following language

Credit Transfers

Revised Section 95488(c)(1)(B)

- *"Requirements for Documenting a Proposed Credit Transfer"* language to be modified
- Paper-based Credit Transfer Form will be discontinued
- All the required information will be captured online in an eForm

Credit Disclosure

- Revision to 95488(e)
- Providing the regulated party the capability to designate whether they would like to buy/sell credits
- Staff be looking into developing an online forum tool through the LRT

Agenda

- Introduction
- Proposed Draft Regulatory Changes
  - Electricity Credits for Fixed Guideway Transportation and Forklifts
  - LCFS Reporting Tool – Credit Bank and Transfer System
  - Miscellaneous Changes
- Next Steps
- Contact Information

Next Steps

- Comments due April 18, 2013
- Submit via email to Katrina Sideco at ksideco@arb.ca.gov
- Next public workshops/workgroup meetings
  - April 4, 2013: Sustainability
  - April 30, 2013: Low-Energy-Use Refinery Provisions, Enforcement Provisions, iLUC Values
  - May 7, 2013: Amendments Workshop, Crude Oil Individual Refinery Approach, OPGEE
- 45-day comment period begins September 9, 2013
- Board Hearing – October 2013

Agenda

- Introduction
- Proposed Draft Regulatory Changes
  - Electricity Credits for Fixed Guideway Transportation and Forklifts
  - LCFS Reporting Tool – Credit Bank and Transfer System
  - Miscellaneous Changes
- Next Steps
- Contact Information

Contact Information

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LCFS Reporting Tool (LRT)-Credit Bank and Transfer System	**Greg O'Brien** (916) 323-0023 gobrien@arb.ca.gov
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http://www.arb.ca.gov/fuels/lcfs/lcfs.htm

Thank You

California Environmental Protection Agency

Air Resources Board

Low Carbon Fuel Standard Proposed Amendments

May 24, 2013

Agenda

- Proposed Draft Regulatory Changes
  - Cost Containment Provisions
  - Electricity Provisions
  - Miscellaneous Revisions
- Next Steps
- Contact Information

Proposed Draft Regulatory Changes

- Cost Containment Provisions
- Electricity Provisions
- Miscellaneous Revisions

Approaches to Further Incent Investment in Low-CI Fuels and Provide Additional Compliance Strategy Options

Background

- State and federal regulations in place to help drive low-CI fuel volumes (e.g., next generation biofuels, electricity, natural gas, etc.)
- 2011 Advisory Panel expressed interest in further incenting investment in low-CI fuels
- Board requested follow-up in Resolution 11-39

Overall Approach

- Consider possible concepts
- Publish descriptions of initial ideas
- Solicit stakeholder input on merits/concerns of concepts
- Continue to work with stakeholders to refine analyses
- Determine which approach(es), if any, enhance the implementation of the LCFS
- Propose amendments to the Board, if needed

The LCFS Incents Low-CI Fuels

Performance-based design gives regulated parties (RPs) the option of investing in the low-CI fuels that best suit their needs

- Investing in mature technologies to help drive down their carbon intensity
- Investing in emerging technologies to find the lowest carbon intensity solution

The LCFS has Several Options for Compliance

Jan – Dec Year A	Jan – Mar Year B	April – Dec, Year B
• Buy low-CI fuels for blending • Produce low-CI fuels to generate credits • Use credits from credit bank • Buy credits from low-CI fuel providers	• Purchase carry back credits*	• If deficit from Year A is less than 10%, choose to carry it over to Year B* ◦ *Use Cost Containment Option/s*

*must still meet Year B target

Goals of Potential Provisions

- Further stimulate investment in low-CI fuels
- Provide regulated parties with additional compliance strategy options

Basic Principles

- Be straightforward and predictable
- Provide some degree of market certainty
- Clearly communicate that low-CI fuels have a secure market
- Minimize extent of market interference

5 Potential Options (So Far)

1. Credit Window
2. Reinvestment Plan
3. Credit Multiplier
4. Credit Clearance
5. Noncompliance Penalty

Option 1 – Credit Window

- Original proposed plan from 2011 Advisory Panel sub-group
- At end of compliance year, if regulated party (RP) unable to purchase credits in the market, they can purchase compliance-only credits from ARB
- ARB provides compliance-only credits at a price set forth in the regulation
- Proceeds from the credit purchases are distributed to parties who use or produce low-CI fuels

Option 2 - Reinvestment

- A price threshold is set in the regulation
- Instead of purchasing compliance-only credits, RPs would invest in projects outlined in the regulation that further the goals of the LCFS
  - Low-CI fuel production
  - Additional infrastructure to distribute low-CI fuels
  - Energy efficiency improvements
  - Others

Option 3 – Credit Multiplier

- Additional LCFS credits introduced by applying a multiplier for low-CI fuels
- Credits would be treated as any other credits in the market
- Approach amplifies signal that low-CI fuels are valuable in the market
- Likely to require additional adjustments

Option 4 – Credit Clearance

- Any RP with net positive credits can pledge credits for the credit clearance process
- Once RPs submit compliance reports, those with deficits declare how they will reconcile the deficits:
  - If < 10% short, carry deficit into following year, as allowed now
  - If > 10%, choose to purchase pro rata share of pledged credits in order to carry negative balance into the following year
- Process available as part of year-end reconciliation
- "Interest bearing" debt

Option 5 – Noncompliance Penalty

- RP out of compliance after the purchase of carry-back credits can opt to pay a pre-established, noncompliance penalty
- Funds would be deposited into the Air Pollution Control Fund

Discussion

- Merits of including such a provision
- Potential downside of including such a provision
- Benefits and challenges of each concept
- Additional concepts
- Consideration of convening a working group

Next Steps and Contact Information

- Comments requested by June 14th, 2013
- Comments and questions may be submitted to:

Ms. Michelle Buffington

mbuffing@arb.ca.gov

916-324-0368

Proposed Draft Regulatory Changes

- Cost Containment Provisions
- Electricity Provisions
- Miscellaneous Revisions

Overview of Electricity Provisions

- Electricity use in fixed guideway transportation and forklifts
  - Board direction to consider off-road sources of electricity
  - Consideration of two methods to incorporate these sources into the regulation
  - Overview of staff proposal
- Modification of requirement to provide metered electricity data for residential charging

Fixed Guideway Transportation and Forklifts Board Direction

- Only on-road vehicles currently qualify for credit generation
- Board directed staff (Res. 09-31 &11-39) to:
  - Evaluate the feasibility of issuing credits for non-road electricity-based transportation sources, including mass transit, and
  - Propose amendments, if appropriate, to the regulation
- Staff is proposing to add fixed guideway transportation and electric forklifts as eligible to opt-in

Fixed Guideway Transportation and Forklifts Consideration of Two Methods

Original staff concept

- Allow these sources to opt into LCFS
- Use modified electricity credit calculation
  - EVs receive credit for low-CI fuel used *and* emissions avoided by conventional vehicle *not* purchased
  - Fixed guideway transportation and forklifts not as directly linked to diesel fuel displacement
  - Therefore, credit calculation should *not* include additional credit for diesel fuel displacement

Fixed Guideway Transportation and Forklifts Consideration of Two Methods (cont'd)

Baseline approach

- Consideration requested by stakeholders
- Incorporate 2010 electricity and natural gas fuel use into diesel baseline
- Modify annual standards based on new diesel baseline
- Allow credit generation from additional future transportation technologies using electricity

Fixed Guideway Transportation and Forklifts Consideration of Two Methods (cont'd)

Staff does *not* recommend baseline approach

- Affects all regulated parties
  - Increases annual CARB diesel deficits
  - Reduces annual credit generation under diesel standard for lower-CI fuels
- Credits for fixed guideway transportation and forklifts will likely not *all* be realized (not all regulated parties will opt-in and report)

Fixed Guideway Transportation and Forklifts Consideration of Two Methods (cont'd)

Staff recommends original concept

- Maintains current baseline and standards
- No change in obligations for diesel regulated parties
- Number of off-road sources that qualify for credit generation is known and fuel use is quantifiable

Fixed Guideway Transportation and Forklifts
Overview of Staff Proposal

Fixed Guideway Transportation

Definition: A fixed guideway system is a system of public transit electric vehicles that can operate only on its own guideway constructed specifically for that purpose, such as light rail or heavy rail, exclusive right-of-way bus operations, and trolley coaches

Fixed Guideway Transportation and Forklifts Overview of Staff Proposal

Fixed Guideway Transportation

- Transit agencies would be eligible to opt in to generate credits, with utilities as back-up
- Credit calculation would not include credit for diesel fuel displacement
- New system extensions may be eligible for full credit calculation if fuel use can be quantified

Fixed Guideway Transportation and Forklifts Overview of Staff Proposal (cont'd)

Electric forklifts

- Utilities would be eligible to include this electricity use
- Fuel use would estimated based on forklift shipments, battery size, operating hours, and load factor
- Credit calculation would not include credit for diesel fuel displacement

Modification of Requirement for Metering of Residential Electricity

- Section 95484(b) requires regulated parties for residential charging to be based on direct metering starting January 1, 2015
- Direct metering means use of a utility meter or submeter in the charging equipment
- Utilities estimate <50% of residential EVs are metered
- Staff proposes to modify the requirement so that an approved estimation method may be used for EVs not using a direct meter

Proposed Draft Regulatory Changes

- Cost Containment Provisions
- Electricity Provisions
- Miscellaneous Revisions

Miscellaneous Updates

- Draft Language for:
  - Diesel Compliance Obligation
  - Battery Switch Stations
  - Energy Density
  - Method 2 Electricity Mix
- Conceptual Ideas for:
  - Method 2 Facility Location
  - Method 2 Retroactivity
  - Credit Trading Provisions
- LRT/CBTS Updates

Diesel Compliance Obligation Retention

Amend Section 95484(a)(2)(B)(4)

Compliance obligation may not be transferred to a buyer of finished diesel fuel, provided the buyer asserts in writing, as part of the transaction, that it intends to sell the diesel as a finished fuel and does not have the ability to blend the finished diesel fuel with additional blendstock (e.g., biodiesel).

Battery Switch Station Owners

Amend Section 95484(a)(6)(C.1)

To receive credit for transportation fuel supplied through battery switch stations, the regulated party must include, in annual compliance reporting, an accounting of the number of battery switch stations and the number of battery switch incidents.

Energy Density

Inclusion of language prior to Table 4

Subject to Executive Officer approval, a regulated party may use an energy density value for a fuel or blendstock that is different than shown in Table 4, provided that energy density value was developed by the Executive Officer pursuant to Method 1 under section 95486(b), or certified by the Executive Officer pursuant to Method 2A or 2B under section 95486(f).

Method 2A/2B Electricity Mix

Amend Section 95486(c)(4) & 95486(d)(6)

An applicant shall use one or two of the following electrical energy generation mixes when calculating the carbon intensities of its feedstock production and fuel production steps, whichever applies (subject to Executive Officer approval):

- The applicable marginal mix specified in CA-GREET 1.8b;
- An applicable marginal mix derived from the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID);

Method 2A/2B Electricity Mix

Amend Section 95486(c)(4) & 95486(d)(6) - *continued*

- The applicable Northwest average mix; or
- The published Bonneville Power Administration (BPA) electrical energy generation mix, provided the applicant can demonstrate by contract or other documentation that the production facility(ies) receives and will continue to receive 100 percent of its electricity from the BPA while it produces fuel for the California market.

Method 2 Facility Location

Amend Section 95486(c)(4) & 95486(d)(6)

- Applicants to provide the *Longitude*, *Latitude*, and *Centroid* of the plants.
- These coordinates will allow staff to verify the plant's existence (domestic/or international) using Google Earth as applicants propose for their carbon intensity certification.

Method 2A/2B CI Retroactivity

Amend Section 95486(f)(2)

- Method 2 applicants may request approval for use of new or revised pathway CIs to apply retroactively to the date on which the applicant's Method 2 application was deemed complete by ARB staff
- Requests for retroactivity beyond the date on which the applicant's Method 2 applicant was deemed complete will not be approved

Credit Transfer Provisions

Amend Section 95488 (c)

- Online credit bank and transfer process (CBTS) to replace paper-based transfers
- All past-due reports to be submitted before credit transfers can be completed
- All "Pending Credit Transfers" initiated in previous compliance period must be completed before submittal of annual reports

Credit Transfer Provisions

Amend Section 95488 (c) - *continued*

- "Delegation Letter" required with LRT-CBTS registration
- Brokers to submit to the jurisdiction of California courts
- "Credit Facilitator" is to refer to RP users, whereas "Brokers" are third party representatives
- Voluntary posting of credits for sale on CBTS forum

Other Provisions

Amend Section 95488 (d) (2) (A)

Default Credit Retirement Hierarchy to be used for the retirement of credits

Amend Section 95484(b)

- Grace period provided for corrections to quarterly reports
- Corrections to be submitted no later than April 30th of the following compliance year

Credit Bank & Transfer System (CBTS)

- CBTS Release – May 17, 2013
  - Online Credit Transfers with Transfer Log
  - Post "Credits to Sell" and Contact Information
  - Broker Registration and "Authorization"
  - Integration with LRT and CABS (credit ledger)
- Phase III Development – Public Disclosure Reports

Miscellaneous LRT System Updates

LRT Updates – May 17, 2013

- Electricity Report Document Upload with Annual Reports
- Positive Total Obligated Volume (TOV) must be maintained
- MCON Reporting Template Posted
- New CBTS User Guide V1.0

Agenda

- Proposed Draft Regulatory Changes
  - Cost Containment Provisions
  - Electricity Provisions
  - Miscellaneous Revisions
- Next Steps
- Contact Information

Next Steps

- Comments due June 14, 2013
- Submit comments via email to Katrina Sideco at ksideco@arb.ca.gov
- Planning additional workshops in June, July, and August
- 45-day comment period scheduled to begin September 9, 2013
- Board Hearing scheduled for October 2013

Agenda

- Proposed Draft Regulatory Changes
  - Cost Containment Provisions
  - Electricity Provisions
  - Miscellaneous Revisions
- Next Steps
- Contact Information

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http://www.arb.ca.gov/fuels/lcfs/lcfs.htm

Thank You

California Environmental Protection Agency

Air Resources Board

Low Carbon Fuel Standard Re-Adoption

May 30, 2014

Agenda

- Proposed Re-Arrangement of LCFS Regulatory Language
- Proposed Revisions
- Environmental Analysis for LCFS & Alternative Diesel Fuel Rules
- Next Steps

Proposed Re-Arrangement of the Regulatory Language

- Summarizes related provisions
- Logical
- Easier to read
- Easier to find provisions

Proposed Revisions

- Indirect Land Use Change Values (status)
- Fuel Pathways
- Electricity Provisions
- Credit Trading Provisions
- Reporting and Recordkeeping Provisions
- Enforcement Provisions

ILUC Update

- Evaluating feedback received from March 11th workshop
  - Reviewing literature provided by stakeholders
  - Utilizing data to support/modify current approach
  - Consulting with subject matter experts
- Model updates
  - Working on including irrigation impacts
  - Reviewing data to refine forestry issue
  - 1st Draft model expected to be available for testing mid-June 2014

ILUC Update (cont.)

- Additional work
  - Potential changes to scenario runs
  - Considering changes to Monte Carlo simulations
- Meetings with stakeholders to discuss ILUC feedback
- Next Workshop (end of June or early July 2014)

Proposed Revisions

- Indirect Land Use Change Values (status)
- Fuel Pathways
- Electricity Provisions
- Credit Trading Provisions
- Reporting and Recordkeeping Provisions
- Enforcement Provisions

Fuel Pathways Agenda

- Two-Tiered Pathway Framework
- Fuel Pathway Process
- New CA-GREET 2.0
- Physical Transport Mode

Two-Tiered Framework

- Providers of conventionally produced first-generation fuels would apply through the Tier 1 process
- The Tier 1 process is simpler and faster than the Tier 2 process
- Applicants would calculate their CIs using a Tier 1 interface in CA-GREET 2.0 (to be discussed later)
- The resulting CI would be, following Executive Officer approval, the certified pathway CI
- Our proposal no longer includes the bins that were proposed earlier

Two-Tiered Framework (cont.)

Two categories of fuels would fall into Tier 2:

- Next-generation fuels
  - Cellulosic alcohols
  - Waste-based fuels (alcohols, drop-ins)
  - Biomethane
  - Hydrogen
- First-generation fuels produced using innovative methods
  - Carbon capture and sequestration
  - Renewable sources of process energy
  - Reduced emissions from feedstock production
  - Unforeseen innovations

Two-Tiered Framework (cont.)

Tier 2 applicants would apply using the familiar Method 1, 2A, and 2B processes

- **Method 1**: Select, subject to Executive Officer approval, a pathway from the Lookup Tables
- **Method 2A**: Apply using a Lookup Table pathway or previously approved, producer-specific pathway as a reference pathway
- **Method 2B**: Apply for a pathway for which no reference pathways exist (new process; new fuel)

Two-Tiered Framework (cont.)

- We propose a proportional substantiality requirement for Method 2A
- For proposed Method 2A pathways with carbon intensities greater than 20 gCO_2e/MJ: 5.5 percent lower than the reference pathway well-to-wheels carbon intensity
- For proposed Method 2A pathways with carbon intensities of 20 gCO_2e/MJ or less: 1 gCO_2e/MJ less than the reference pathway well-to-wheels carbon intensity

Fuel Pathway Process

We propose to streamline the application process in two ways:

- The current fuel pathway application and producer registration processes would be consolidated
- The consolidated process would be completed interactively through the LCFS Reporting Tool (LRT) web portal

All applicants, regardless of Tier or Method, would start the process by completing a web-based New Pathway Request Form

Fuel Pathway Process (cont.)

- The New Pathway Request Form would obtain all information needed for:
  - Starting the pathway application process
  - Creating a new (initially inactive) record in the LRT
- Once the applicant's Tier placement has been approved, the applicant can:
  - Submit required Tier 1 materials
  - Request a Tier 2 Method 1 (Lookup Table) pathway
  - Submit required Tier 2 Method 2 materials
- All application materials can be securely uploaded via the LRT
- Upon approval, the inactive LRT record is activated

New CA-GREET 2.0

- We are processing to update the current CA-GREET 1.8b
- Two primary advantages
  - Updated life cycle inventory data
  - Ability to build a greater variety of fuel pathways
- We are basing this update on Argonne National Lab's GREET 2013

New CA-GREET 2.0 (cont.)

- Tier 1 Calculator for first-generation fuels
  - Starch- and sugar-based ethanol
  - Bio- and renewable diesel
  - Fossil and natural gas
- Tier 2 Modules for next-generation fuels
  - Innovative process, new feedstocks
  - User's calculation with CA-GREET
  - Upstream and other plant specific parameters

Evidence of Physical Transport Mode

- Nomenclature change
- Electricity exempt from this requirement
- Clarification for biogas injected into interstate pipeline
  - Must be used for transportation purpose in California
  - No double-counting of emission reductions
- Limit retroactivity of credits based on this provision to 2 quarters max

Proposed Revisions

- Indirect Land Use Change Values (status)
- Fuel Pathways
- Electricity Provisions
- Credit Trading Provisions
- Reporting and Recordkeeping Provisions
- Enforcement Provisions

Changes to Electricity Provisions

- Proposing to *exclude* some supplemental information that is now required in annual reporting
  - Number of credits generated, sold, and banked
  - Number of EVs operating in service territory
  - Number of charging stations and charging incidents
- Change in heavy duty EV EER based on data for EV buses operating in CA (current 2.7, proposed 3.8)

Changes to Electricity Provisions (cont.)

- Opportunity for transit agencies to generate credits for fixed guideway systems
- Opportunity for utilities to generate credits for electric forklifts
- Slightly modified credit formula for fixed guideway and forklift credits to account for exclusion in baseline
- Adding new EER values
  - Heavy rail 4.6
  - Light rail and trolley bus 3.3
  - Electric forklifts 3.1
- Various edits to promote clarity

Changes to Electricity Provisions (cont.)

- Section 95484(b)(3)(C)(1) states that effective January 1, 2015, reporting of electricity dispensed to electric vehicles in residences must be based on direct metering
- Many EV owners are choosing to charge at residences with no meter
- A robust estimation method has been developed for use by CalETC members
- Staff is proposing that an approved estimation technique be allowed for credit generation after January 1, 2015

Proposed Revisions

- Indirect Land Use Change Values (status)
- Fuel Pathways
- Electricity Provisions
- Credit Transactions
- Reporting and Recordkeeping Provisions
- Enforcement Provisions

Credit Transactions

- **Consolidated regulatory text from various sections into one place [new section 95487]**
- **New User Related Definitions**
  - "Broker"
  - "Credit Facilitator (CF)"
- **New Acronyms Added: "LRT-CBTS"**

Credit Transactions (cont.)

- **Credit Retirement Hierarchy**
  - Credits acquired as a "carryback" purchase
  - Credits acquired during a previous compliance period
  - Credits generated in the earliest previous quarter
- **Credit Transfers**
  - All credit transfers to occur in LRT-CBTS
  - Online Credit Transfer Form (CTF)
  - 15 day period for Buyer to "Complete" a transfer
  - Regulated parties can authorize "Broker(s)"
  - Prohibited transactions

Proposed Revisions

- Indirect Land Use Change Values (status)
- Fuel Pathways
- Electricity Provisions
- Credit Transactions
- Reporting and Recordkeeping Provisions
- Enforcement Provisions

Definitions

Definitions Added

- **Reported Fuels Definitions:**
  - "Liquefied Compressed Natural Gas (L-CNG)"
  - "Biogas L-CNG"
- **Definition of Fixed Guideway Transportation**
- **Reporting Related Definitions**
  - "Total Obligated Amount"
  - "Product Transfer Document (PTD)"
  - "Fuel Transaction Form (FTF)"
  - "Reporting Party": pertains to chain of custody reporting

Definitions & Acronyms

Definitions Added (cont.)

- **Revised "Transaction Type" definition**
  - Updated "Production" with "Production for use in California"
  - Added "EV Charging" and "Forklift Charging
  - Added "Fixed Guideway Charging"
  - Added "NGV Fueling"
- **New acronyms**
  - "HDV-CIE," "HDV-SIE," "NGV," and "L-CNG"
  - "LRT-CBTS"
  - "TOA"

Reporting and Recordkeeping

- Pending credit transfers must be completed before annual report can be submitted
- Clarify reporting fuel production company ID and facility ID
  - Ethanol, biomass-based diesel, biogas, hydrogen facilities to be reported
  - Not required for CARBOB, diesel, fossil natural gas or electricity

Reporting and Recordkeeping (cont.)

- **Record Retention period extended to 5 years**
- **Documenting fuel transfers**
  - Product Transfer Documentation
  - Fuel Transaction Form
- **Correcting a previously submitted report**
  - Unlock Report Request Form
  - Provide Justification and Specify Changes
  - Corrected reports do not preclude enforcement based on misreporting

Documenting Fuel Transfers

Product Transfer Document (PTD)

Includes these parameters when obligation is passed:

- Transferor Company Name, Address and Contact Information
- Transferee Company Name, Address and Contact Information
- Date of Title Transfer
- Fuel Pathway Code (FPC) and Carbon Intensity (CI)
- Volume/Amount
- A statement identifying that the LCFS Obligation is passed to the transferee
- Fuel Production Company ID and Facility ID as registered with RFS2 program or LCFS program if not RFS2 registered

Documenting Fuel Transfers (cont.)

Fuel Transaction Form (FTF)

- Used to obtain confirmation and reconciliation prior to reporting
- Record aggregated and non-aggregated data from PTDs
- Upload and validate FTFs quarterly in LRT-CBTS
- Preview and route to Business Partners within LRT-CBTS
- Partner Confirmation and Reconciliation
- Significant reduction in report corrections

Documenting Fuel Transfers (cont.)

Fuel Transaction Form (FTF)

Includes these parameters:

- Business Partner - FEIN and Name
- Business Partner Name
- Year and Quarter
- Fuel Pathway Code (FPC)
- Volume/Amount
- Transaction Type
- Production Company ID
- Production Facility ID
- Physical Transport Mode Code
- Aggregation Indicator (T/F)
- Title Transfer Date or Aggregated Transaction Date (last day of quarter if aggregated) and a memo (optional)

Documenting Fuel Transfers (cont.)

FTF Data File Example

BusinessPartner	BusPartnerName	Year	Quarter	FuelPathwayCode	Amount	TransactionType	EPACompanyID	EPAFacilityID	PhysicalPathwayCode	Aggregation(T/F)	Transaction Date	Memo (optional)
34-0135398	Acme Oil	2016	1	Ethanol from CornETHC008	20000	Sold with obligation transfer	8920	32066	PHY02	T	3/31/2016	
34-0135398	Acme Oil	2016	1	Ethanol from CornETHC004	100000	Purchased without obligation transfer	3921	52186	PHY02	F	1/12/2016	
55-0123890	Alt-Fuel Co	2016	1	Ethanol from CornETHC008	55000	Purchased with obligation transfer	5024	10255	PHY05	T	3/31/2016	
55-0123890	Alt-Fuel Co	2016	1	Ethanol from CornETHC004	5800	Purchased with obligation transfer	5024	10255	PHY05	F	1/31/2016	
55-0123890	Alt-Fuel Co	2016	1	BiodieselBIOD007_1	15000	Sold with obligation transfer	1423	40752	PHY03	F	1/15/2016	
34-0135398	Cellulo Fuels	2016	1	Ethanol from CornETHC008	20000	Sold without obligation transfer	8920	32066	PHY02	T	3/31/2016	
34-0135398	Cellulo Fuels	2016	1	Ethanol from CornETHC004	100000	Purchased with obligation transfer	3921	52186	PHY02	T	3/31/2016	
65-0123890	Best Fuels	2016	1	Ethanol from CornETHC008	55000	Purchased with obligation transfer	5024	10255	PHY05	T	3/31/2016	
65-0123890	Best Fuels	2016	1	Ethanol from CornETHC004	2600	Purchased with obligation transfer	5024	10255	PHY05	T	3/31/2016	
35-5135991	A-1 Fuels	2016	1	BiodieselBIOD007_1	15000	Sold with obligation transfer	1423	40752	PHY03	F	3/20/2016	
35-5135991	A-1 Fuels	2016	1	Ethanol from CornETHC008	25000	Sold with obligation transfer	8920	32066	PHY02	T	3/31/2016	
35-5135991	A-1 Fuels	2016	1	Ethanol from CornETHC004	100000	Purchased with obligation transfer	3921	52186	PHY02	T	3/31/2016	
15-0123894	Positi Inc	2016	1	Ethanol from CornETHC008	55000	Purchased without obligation transfer	5024	10255	PHY05	F	2/11/2016	
15-0123894	Positi Inc	2016	1	Ethanol from CornETHC004	3600	Purchased with obligation transfer	5024	10255	PHY05	T	3/31/2016	
15-0123894	Positi Inc	2016	1	BiodieselBIOD007_1	35000	Sold without obligation transfer	1423	40752	PHY03	F	3/15/2016	

Documenting Fuel Transfers (cont.)

Schedule for Submitting Fuel Transaction Form Data

- FTFs are required to be submitted within 20 business days of quarter end date
- FTFs are to be acknowledged by Business Partners within 30 days of quarter end date

Proposed Revisions

- Indirect Land Use Change Values (status)
- Fuel Pathways
- Electricity Provisions
- Credit Transactions
- Reporting and Recordkeeping Provisions
- Enforcement Provisions

Agenda

Enforcement Provisions

- Executive Officer Authority
- Enforcement Protocols
- Jurisdiction
- Violations

Executive Officer Authority

New Section 95490.2

ARB Executive Officer has the authority to:

- Suspend an account
- Revoke credits
- Hold credits
- Limit or prohibit transfers of credits

Draft Amendment-Enforcement

- **Enforcement Protocols**

  Section 95492 [Formerly Section 95490]

- **Jurisdiction**

  Section 95493 [Formerly Section 95480.5]

Draft Amendment Violations

- **Violations**

  Section 95494 [Formerly Section 95484(d)]

- **Stakeholder Feedback**

  Generally supportive with some sensitivity to what is deemed a violation

Draft Amendment Violations (cont.)

Violation Language to include:

- **Violation examples**
  - Late, not reporting, or inaccurate reporting
  - Annual compliance: deficits
- **Penalties**
  - Existing H & S Code governs
  - Per deficit

Agenda

- Proposed Re-Arrangement of LCFS Regulatory Language
- Proposed Revisions
- Environmental Analysis for LCFS & Alternative Diesel Fuel Rules
- Next Steps

Environmental Analysis for LCFS and Alternative Diesel Fuel (ADF) Rules

- Environmental Analysis (EA) will be prepared to analyze environmental impacts of both the LCFS and ADF regulations since the two are interrelated
- CEQA checklist will be used to identify and evaluate potential impacts to environmental resource areas
- The EA will include:
  - Methods of compliance
  - Beneficial impacts and adverse impacts
  - Mitigation measures
  - Alternatives Analysis

2009 Environmental Analysis for the LCFS

The Air Quality Analysis in the EA prepared for the LCFS in 2009 identified:

- Significant GHG reductions due to production and use of lower CI fuels
- Potential reductions due to changes in vehicle fleet composition
- Estimated 2020 Biofuel Production Facilities
- No change in emissions from petroleum refineries, power plants, or existing corn ethanol facilities over baseline emissions
- Criteria pollutant emissions related to truck trips associated with delivery of feedstock and finished fuel
- Emissions offset by using newer trucks as prescribed by other State and federal regulations (such as LEV and CAFÉ standards)
- Health risk analysis to assess localized impacts

EA for Proposed 2014 Rules

- As part of 2014 EA, staff will assess beneficial and adverse environmental impacts from the proposed 2014 LCFS and ADF regulations
- Conclusions in 2014 EA may vary from those previously reached in the 2009 LCFS EA
- Air Quality Analysis will be a major focus of 2014 EA, as it was in the 2009 analysis
- Air Quality Analysis will address the potential for proposed LCFS and ADF regulations to increase NOx emissions

Public Feedback on Scope of the EA

ARB staff invites feedback on appropriate scope and content of the EA as it's being developed. The scope and content of the EA would include:

- Identification of potentially significant adverse impacts from the LCFS and ADF regulations
- Alternatives to the proposed LCFS or ADF regulations that might avoid or substantially lessen significant adverse impacts
- Mitigation measures that should be analyzed for any significant adverse impacts

We welcome your feedback on the planned EA

Please submit to Katrina Sideco (ksideco@arb.ca.gov)

Agenda

- Proposed Re-Arrangement of LCFS Regulatory Language
- Proposed Revisions
- Environmental Analysis for LCFS & Alternative Diesel Fuel Rules
- Next Steps

Next Steps

- Feedback due June 13, 2014
- Submit via email to Katrina Sideco at ksideco@arb.ca.gov
- Additional public workshops
- Board Update – Summer (July?) 2014
- Staff report – Summer (September?) 2014
- Board Hearing – Fall (November?) 2014

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http://www.arb.ca.gov/fuels/lcfs/lcfs.htm

Thank You

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

Attachment "B"

Appendix D

Compliance with the Revised LCFS Program and Associated Economic Impacts

Prepared by Edgeworth Economics

Updated September 22, 2015[1]

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.[2] 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.[3] 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[4] with an average CI value of about 82, to cane ethanol from Brazil, which currently has an average CI value of about 72.[5] 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

[1] This analysis is an update of the version filed on February 17, 2015.
[2] CARB, *Staff Report: Initial Statement of Reasons for Proposed Rulemaking*, December 2014 ("ISOR"), p. ES-3.
[3] ISOR, p. B-39.
[4] 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]
[5] ISOR, p. B-39.

Attachment "B"

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 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.[6]

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.[7] 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.[8]

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—average for 12 months through September 15, 2015 [source: Platts] and 2016 forecast [source: OECD-FAO, *Agricultural Outlook 2015-2024*].
- Rail freight rates from Midwest refinery locations to California, provided by Growth Energy members.

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[6] The average output of operating ethanol facilities is about 76 million gallons of ethanol per year. [RFA website at www.ethanolrfa.org/pages/statistics]

[7] ISOR, p. VII-1.

[8] 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]

- Maritime freight rates from Brazil to California, including tariff and terminal charge [source: Odin Marine Group, *Ethanol Report*, January 2015 and Growth Energy members].
- D5 and D6 Renewable Identification Number (RIN) prices—average for 12 months through September 15, 2015 [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[9], while Midwest facilities with CI ratings in the low 90s continue to deliver product. At the average ethanol and RIN prices experienced during the 12-month period through September 15, 2015, the value of an LCFS credit would need to rise to $136 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 experienced substantial volatility in recent months; based on the average in August 2015, an LCFS credit price of $82 would incentivize the same switch, although the most recent spreads indicate a somewhat higher value ($163, based on the average value for the partial month from September 1 through September 15).

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 only about $4 (based on the most recent RIN spreads) would cause a switch from 92.4-CI corn ethanol to cane ethanol; and a credit price of only $5 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.[10] At that rating, LCFS credit prices as low as $1 - $2 would result in a switch away from even the lowest-rated facilities in the Midwest.[11] In this scenario, even Midwest facilities with CI ratings as low as 70, which CARB claims will be the

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

average rating of the Midwest corn facilities still delivering product to California as of 2016[12], would be at risk. 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 plausible, but probable if sufficient ethanol is available from Brazil, even at modest credit prices well below CARB's projected level of $100.[13]

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[14]), 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.[15] 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

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[12] ISOR, p. B-39.

[13] 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.

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

[15] 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.

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 times the direct employment impact) to about 7.[16] Applying a figure of 4 to the direct employment impacts calculated above implies a loss of approximately 1,760 jobs in ethanol producing regions.

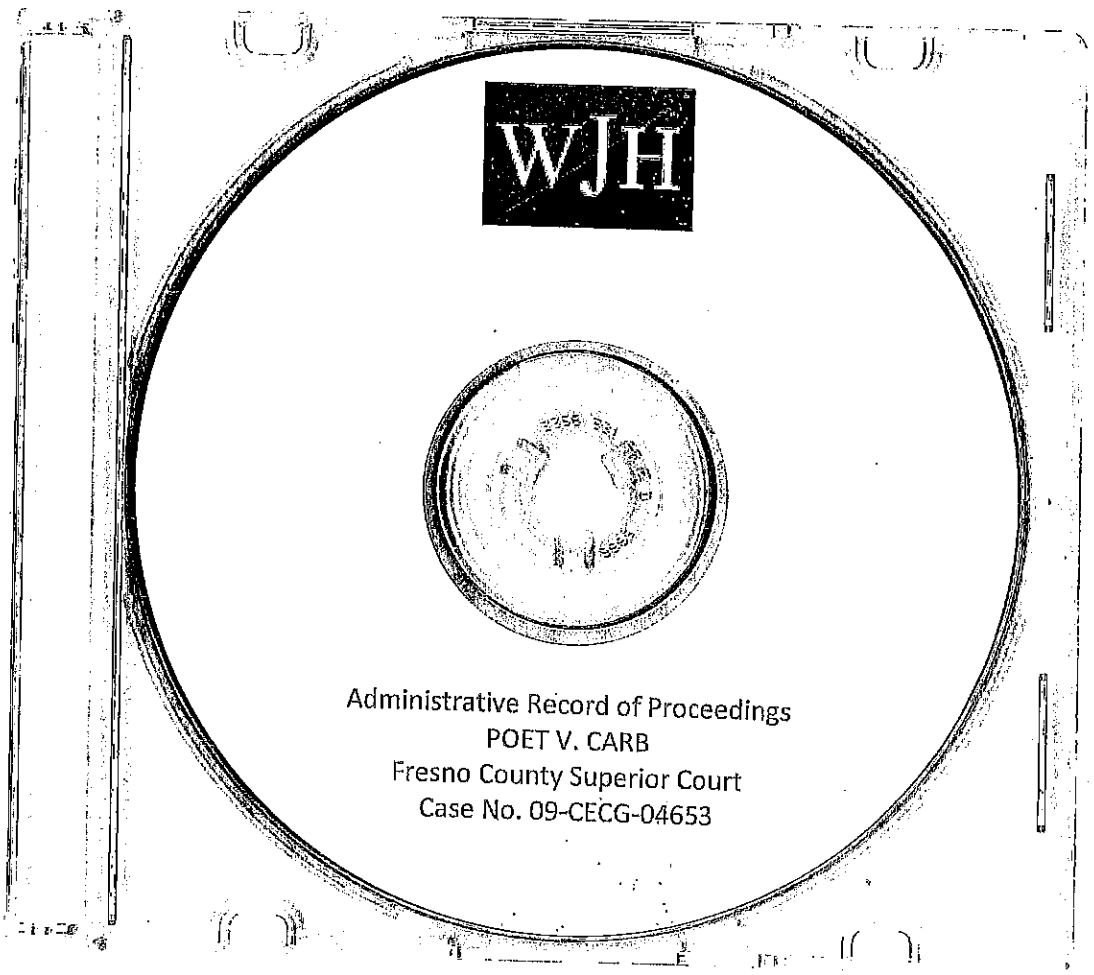
Even assuming that the facilities forced out of the California market could find customers outside the U.S., there would still be substantial costs to the industry. For example, transport of ethanol from the Midwest to Brazil would entail increased logistics costs of approximately 10 cents per gallon[17], or $55 million per year, assuming sufficient demand in Brazil for all 550 million gallons of displaced corn ethanol.

[16] 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.

[17] Based on the sources described above.

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

Attachment "C"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Administrative Record of Proceedings
POET V. CARB
Fresno County Superior Court
Case No. 09-CECG-04653