California Environmental Protection Agency

Air Resources Board

Staff Report: Initial Statement of Reasons for Proposed Rulemaking

Proposed Amendments to the Low Carbon Fuel Standard

Stationary Source Division
Transportation Fuels Branch
Alternative Fuels Branch

October 2011

State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING

Public Hearing to Consider

PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION

To be considered by the Air Resources Board on December 15, 2011, at:

California Environmental Protection Agency
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1001 “I” Street
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Glossary

List of Acronyms and Abbreviations

ARB or Board	California Air Resources Board
BEV	Battery Electric Vehicle
CA-GREET	California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
CARBOB	California Reformulated Gasoline Blendstock for Oxygenate Blending
CBI	Confidential Business Information
CEQA	California Environmental Quality Act
CI	Carbon Intensity
CO_2, CO_2e	Carbon Dioxide, Carbon Dioxide Equivalent
CCS	Carbon Capture and Sequestration
CNG	Compressed Natural Gas
DGS	Distillers Grains with Solubles
EERs	Energy Economy Ratios
EO	Executive Officer
EWG	Electricity Workgroup
EV	Electric Vehicle(s)
EVSE	Electric Vehicle Service Equipment
EVSPs	Electric Vehicle Service Provider(s)
FCV	Fuel Cell Vehicle
gCO_2e/MJ	Grams of CO_2 Equivalent per Megajoule
gge	Gasoline Gallon Equivalent
GHG	Greenhouse Gas
HCICO	High Carbon-Intensity Crude Oil
iLUC	Indirect Land-use Change
ISOR	Initial Statement of Reasons
LCA	Lifecycle Assessment
L-CIS	LCFS Central Information System
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas
LRT	LCFS Reporting Tool
OPIS	Oil Price Information Service
$MMTCO_2e$	Million Metric Tons of CO_2 Equivalent
$MTCO_2e$	Metric Ton of CO_2 Equivalent
PHEV	Plug-in-Hybrid Electric Vehicles
RFS2	Renewable Fuel Standard 2
RINs	Renewable Identification Numbers
TOU	Time-of-Use
ULSD	Ultra Low Sulfur Diesel

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Executive Summary

The California Air Resources Board (ARB or Board) staff is proposing amendments to the Low Carbon Fuel Standard (LCFS) regulation.[1] The primary objectives of the proposed amendments are to clarify, streamline, and enhance certain provisions of the regulation. It should be emphasized that the proposal primarily involves refining and improving certain aspects of the regulation and that the vast majority of the regulation remains unchanged by this proposal. Therefore, this Initial Statement of Reasons (ISOR or Staff Report) builds on the comprehensive and extensive work that was done in support of the original 2009 LCFS rulemaking.[2] Accordingly, the rulemaking record and supporting materials for that original rulemaking generally remain applicable to this staff proposal, and this Staff Report addresses only the incremental changes related to the proposed amendments.

Staff developed these proposed amendments to support the overall purpose of the LCFS, which is to reduce greenhouse gas emissions (GHG) by reducing the full fuel-cycle, carbon intensity (CI) of the transportation fuel pool used in California.[3] The proposed amendments address several aspects of the regulation, including: reporting requirements, credit trading, regulated parties, opt-in and opt-out provisions, definitions, and other clarifying language. A summary description of each of the proposed amendments is provided later in this section.

After the Board approved the LCFS for adoption on April 23, 2009, the regulation entered into full effect on April 15, 2010. Implementation of the CI-reduction requirements and compliance schedules began on January 1, 2011. Since the regulation went into effect, regulated parties have operated under the LCFS program with no significant compliance issues.

In short, the LCFS is working as designed and intended. Regulated parties are using the LCFS Reporting Tool (LRT) to submit electronically their quarterly progress and annual compliance reports with no known significant problems. Further, fuel producers are innovating and achieving material reductions in their fuel pathways' carbon intensities, an effect the LCFS regulation is expressly designed to encourage, which is reflected in the large number of applications submitted under the "Method 2A/2B" process. Indeed, 26 submittals for Method 2A/2B applications, representing over 100 individual new or modified fuel pathways with substantially lower carbon intensities

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[1] Codified at title 17, California Code of Regulations (CCR), sections 95480 through 95490.
[2] See the initial statement of reasons (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf and http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor2.pdf) and final statement of reasons (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsfsor.pdf) for the original 2009 LCFS rulemaking, all of which are incorporated herein by reference.
[3] Adopted pursuant to California Global Warming Solutions Act of 2006 (AB 32) and codified at Health and Safety Code, sections 38500 through 38599.

have been posted to date by staff on the LCFS portal.[4] Substantial credit generation also indicates a successful implementation of the program; in the first quarter of 2011 alone, regulated parties reported generating about 225,000 metric tons (MT) of LCFS credits versus about 150,000 MTs of deficits.

To the extent questions from stakeholders have arisen, they have been addressed through a series of regulatory advisories[5] broadcast to stakeholders subscribed to the LCFS email notification list serve. Staff also provided a LCFS Guidance Document[6] that addresses frequently asked questions, and communicated with individual stakeholders on their specific questions.

With that said, most complex regulations like the LCFS can generally benefit from further refinements. Based on feedback from regulated parties as well as other stakeholders, and by reviewing lessons learned since implementation began, staff identified specific areas of the regulation for clarification and other improvements. These proposed improvements are expected to better ensure the successful implementation of the LCFS program.

To develop these proposed amendments, ARB staff conducted three public workshops, held numerous meetings and discussions with interested parties, and worked closely with stakeholders, including transportation fuel providers and importers, environmental groups, academia, and other interested parties. Materials presented and discussed by staff and other parties at the public meetings were made available for public review on ARB's main LCFS informational portal.[7]

Concurrent with the development of these amendments, ARB staff conducted the first review of the LCFS program. Section 95489 of the regulation requires the Executive Officer (EO) to establish an advisory panel and conduct two reviews of the implementation of the LCFS program through a public process. The reviews are required to address a broad range of implementation topics, including the program's progress against LCFS targets, whether adjustments to the compliance schedule are needed, advances in fuels and production technologies, hurdles or barriers and recommendations for addressing such barriers, and other relevant topics. Section 95489(a) of the regulation defines the minimum scope of each review. Several of the amendments proposed in this Staff Report take into consideration discussions with the advisory panelists on related topics.

[4] Pursuant to LCFS Regulatory Advisory 10-04, regulated parties are permitted to use the Method 2A/2B pathways and carbon intensities when they are posted by ARB staff prior to a hearing by the Executive Officer to consider taking action on such proposed pathways. See http://www.arb.ca.gov/fuels/lcfs/122310lcfs-rep-adv.pdf.

[5] See Advisories 10-02, 10-03, 10-04, and 10-04A at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.

[6] See http://www.arb.ca.gov/fuels/lcfs/LCFS_Guidance_(Final_v.1.0).pdf.

[7] See www.arb.ca.gov/fuels/lcfs/lcfs.htm and www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm.

Further, it should be noted that the proposal does not reflect the staff's ongoing work to update the indirect land-use change analysis (iLUC),[8] which was considered too preliminary at the time of this Staff Report's release to serve as the basis for a proposed amendment on the iLUC carbon intensity values. This ongoing work is expected to be completed during the latter half of 2012, at which time the staff expects to propose regulatory amendments, if appropriate, for the Board's consideration to reflect the completed update.[9]

Summary of Proposed Amendments

The proposed amendments include revisions to specific provisions and requirements of the regulation. The following is a summary description of each of the proposed amendments:

Opt-In and Opt-Out Provisions

Various low-carbon and exempted fuel providers with fuels already meeting the 2020 carbon intensity standards have expressed their intent and desire to opt into the LCFS program as a regulated party, but they are unsure of the process and if they can opt out in the future. To address this concern, staff is proposing to add specific opt-in and opt-out provisions in the regulation. These provisions would specify the process and information submittals needed for a fuel provider to opt in or opt out as a regulated party.

In addition, several out-of-state fuel producers and some in-state fuel suppliers expressed the desire to opt into the program as regulated parties. The current regulation does not confer regulated party status to these out-of-state entities because of jurisdictional concerns. These parties are further upstream and closer to the starting point of fuel production than currently designated regulated parties (i.e., fuel importers and California producers). Staff is proposing regulatory amendments that would permit such entities to voluntarily elect to become regulated parties and become subject to California jurisdiction. These proposed opt-in provisions are intended to work in tandem with the enhanced regulated party changes described below.

Enhanced Regulated Party

Staff has identified a couple ways to enhance the regulated party definitions so that more fuel producers and suppliers can become regulated parties. First, staff is proposing to amend the definitions of "producer," "importer," and "import facility" to

[8] See Chapter IV, section C, of the 2009 LCFS staff report (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf) at IV-16 through IV-48 for a general discussion of iLUC analysis. The current work is evaluating advancements in the iLUC analysis for corn ethanol, sugarcane ethanol, and soybean biodiesel.
[9] See http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm for presentations and materials discussed to date related to the iLUC work.

include out-of-state and intermediate entities, such as fuel distributors, suppliers, and marketers as regulated parties. This would have the effect of conferring initial regulated party status to those entities that own title to a fuel and actually deliver or cause delivery of a transportation fuel to California. Second, as noted above, several out-of-state fuel providers and intermediate entities have expressed their desire to be able to opt in as a regulated party under the regulation. Further, several gas utilities have expressed a desire to opt into the program when a person, who would normally be qualified to opt in as a regulated party for compressed natural gas (CNG), decides not to do so. Staff is proposing language to permit these entities to opt into the regulation under specified conditions.

Method 2A/2B Certification

The approval of new or modified fuel pathways (i.e., “Method 2A/2B approval”) under the regulation currently requires a formal rulemaking. A formal rulemaking is a lengthy and resource-intensive undertaking, requiring an “initial statement of reasons”; a 45-day comment period; a “final statement of reasons,” in which comments received on the proposed rulemaking are responded to; and a public hearing. This formal process typically takes about six months to a year. Based on the potential efficiency gains and in recognition that the activities to process and evaluate Method 2A/2B applications are becoming more routine, the Board directed staff under Resolution 09-31 to investigate the feasibility of converting the rulemaking process for the approval of new or modified pathways into a more streamlined certification process.[10] Based on this investigation, staff proposes to convert the current application process into a certification program to facilitate more expeditious reviews of Method 2A/2B submittals. The staff’s proposal maintains transparency and accountability by including provisions retaining the public’s ability to review and comment on proposed certifications.

Credit Trading

The current regulatory text permits regulated parties to trade and transact LCFS credits, but it does not specify ARB’s role in the transactions, information about the credit market to be published by ARB, and other relevant provisions and requirements. Therefore, staff is proposing a new section to be added to the LCFS regulation to provide more detail on how credits and deficits will be tracked. The proposal also specifies the process for regulated parties to use for acquiring, banking, transferring, and retiring credits. Other provisions relevant to credit trading are also proposed.

High Carbon-Intensity Crude Oil (HCICO)

The current regulation contains a provision requiring regulated parties of petroleum-based fuels to account for their use of high carbon-intensity crude oil (HCICO) in their crude slates. The existing regulation employs a simple “bright line” approach to assigning carbon intensities to petroleum transportation fuels in California

[10] See http://www.arb.ca.gov/regact/2009/lcfs09/res0931.pdf.

(i.e., a crude is determine to either be a HCICO or a non-HCICO). Although the current approach has the benefit of being relatively simple, it has been suggested that, to reflect current market realities, a better approach be developed to account for a continuum of crude oil carbon intensities.

Accordingly, staff is proposing a new accounting approach that would require such regulated parties to account for: (1) the difference in carbon intensity between the LCFS compliance schedules and a specified baseline (i.e., the “baseline deficit”), and (2) the incremental difference in carbon intensity between the specified baseline and the actual carbon intensity of petroleum fuels used in California within a specified timeframe (i.e., the “incremental deficit”). In essence, this approach would require the California petroleum-refining sector to not only account for the carbon-intensity reduction that the compliance schedules would otherwise require relative to a specified baseline, but it would also require this sector to account for changes in the actual carbon intensity of petroleum fuels due to the use of HCICO feedstocks.

The proposal described above calls for the new approach to go into effect on January 1, 2013. Because there could be a lag between implementation of the new approach and the existing “HCICO/non-HCICO” provisions, the proposal also specifies a list of crude oils that the Executive Office has determined, in consultation with stakeholders and sister agencies, to be clearly non-HCICO feedstocks. This list would sunset when the new approach described above goes into effect.

<u>Electricity Regulated Party Revisions</u>

The Board directed staff in Resolution 09-31 to review the provisions applicable to regulated parties for electricity and propose amendments if appropriate. Since the regulation was approved by the Board, the markets for electric vehicles (EV) and EV fueling infrastructure have evolved and continue to evolve. To reflect this market evolution, staff is proposing amendments that would better define the potential regulated parties for electricity and the order of priority in which that status would be conferred. The proposal would apply to potential regulated parties such as electric utilities, non-utilities installing electric vehicle service equipment (EVSE) with a customer contract, fleet operators, and business owners.

<u>Energy Economy Ratios</u>

In Resolution 09-31, the Board directed staff to reevaluate the Energy Economy Ratios (EERs) for heavy-duty vehicles burning CNG or liquefied natural gas (LNG) vehicles and update them if appropriate. Accordingly, staff has reevaluated those EERs and proposes to revise them to reflect updated information. In addition, staff has reevaluated and proposes revisions to the EERs for light-duty battery electric vehicles (BEV), plug-in-hybrid electric vehicles (PHEV), and light-duty fuel cell vehicles. These proposed changes to the EERs, along with proposed changes to how they are used in the calculations specified in the regulation, reflect engine efficiency and fuel economy data that were not available during the original 2009 rulemaking.

Reporting Requirements

Staff proposes several amendments to various reporting requirements to simplify the provisions, including elimination of reporting energy volumes in “gasoline gallon equivalent” units and the reporting of renewable identification numbers (RINs). Similarly, staff also proposes to simplify reporting of significant figures by requiring such figures to be expressed in nearest whole units. Finally, staff proposes to require the use of the LCFS Reporting Tool (LRT) for reporting purposes. Although the current regulatory text does not explicitly require use of the LRT, it has become the *de facto* standard for reporting purposes, and staff’s proposal would simply formalize this.

Miscellaneous Changes

The proposal contains a number of miscellaneous changes. This includes deleting the reference to the alternative fuel specification in the definitions of “compressed natural gas,” “biogas,” and “liquefied natural gas.” Staff proposes this change to better reflect the GHG basis of the regulation. Further, staff proposes amendments that would codify a number of provisions specified in the LCFS regulatory advisories released to date. Finally, staff proposes a number of grammatical, typographical, or other non-substantial corrections.

Impacts of Proposed 2011 Amendments to LCFS Regulation

Environmental Impacts

The environmental analysis published in the 2009 LCFS ISOR focused on the significant GHG emission reductions that the regulation would achieve through the production and use of lower-CI transportation fuels. Staff estimated that a reduction of about 16 million metric tons of CO_2-equivalent ($MMTCO_2e$) would come solely from the combustion of transportation fuels in California in 2020. A thorough description of the estimated environmental impacts of the LCFS can be found in the 2009 LCFS ISOR; the assumptions and resulting analyses contained therein are still considered valid.

For the proposed amendments, staff has estimated that there are no significant adverse environmental impacts. Most of the proposed amendments – opt-in/opt-out, enhanced regulated party, credit trading mechanism, Method 2A/2B certification, etc. – are related to making the implementation of the LCFS run more smoothly. There may be environmental benefits related to additional credits generated and introduced into the LCFS credit market, as these credits may obviate the need for additional fuels to be produced at biorefineries. However, as a result of the proposed amendments we do not anticipate a substantive change in GHG emission reductions (there may be a slight increase in reductions due to changes to the baseline). Further, as a result of the proposed amendments, we do not anticipate local adverse environmental impacts.

Economic Impact

Staff estimates that the proposed amendments will generally have a positive economic impact on regulated parties, largely due to additional credits expected to be introduced into the LCFS credit market. Clarifications on opting into the LCFS, a credit-trading mechanism, enhanced regulated parties, and who gets electricity credits are all expected to attract additional credits to the LCFS program. These additional credits should keep credit prices lower than they would otherwise be, thus reducing compliance costs.

The proposed Method 2A/2B certification process will streamline the approval process for stakeholders while maintaining a transparent process. Staff expects the proposed amendments will have no fiscal impacts for federal, state, or local governments.

Analysis of Alternatives

Staff evaluated several alternatives to the proposed amendments. The alternatives are presented below:

1. Take no action (i.e., leave current regulatory language as is). As discussed in Chapter VII, Analysis of Alternatives, this alternative was deemed not feasible because it would not effectuate the various clarifications and enhancements contained in the staff proposal. Consequently, implementation of the regulation would not be as successful as it could be with the staff's proposed changes.

   For example, as noted previously, the proposed enhanced regulated party definitions and opt-in and opt-out provisions are intended to help encourage additional entities to participate in the LCFS regulation. In a number of cases, those proposed changes would help capture and bring into the LCFS credit market those credits that might otherwise be "orphaned" because their generators did not choose to enter into the program. Other refinements that would be foregone in a "no action" alternative would include updates to the EERs, changes to clarify and make transparent credit trading, and the streamlining benefits of converting the Method 2A/2B approval process from a rulemaking to a certification process.

   The two major substantive portions of the staff's proposal that would be adversely affected under a "no action" alternative would be the proposal's changes to the electricity regulated party provisions and the provisions for addressing the carbon intensity of petroleum crude oils and fuels derived from such crude oils. The no-action alternative would prevent the staff's proposed improvements to the electricity regulated party provisions. As noted earlier, the staff's proposal with regard to electricity regulated parties would better reflect the evolution of the EV sector since the 2009 approval of the LCFS regulation. Under the no-action alternative, these evolutionary changes in the EV market would not be reflected in the regulation, thereby depriving credits to those entities that would otherwise qualify for regulated party status under the staff's proposed changes. The no-action alternative would also deprive consumers with the public education and other value-added benefits called for under the staff's proposal.

For petroleum regulated parties, the no-action alternative would mean that those entities would need to continue to meet the existing requirements for high intensity crude oil (HCICO). Because the HCICO provisions are tied to a 2006 crude slate or "basket," the no-action alternative would preclude adjustments to the HCICO provisions that would better reflect the petroleum market that has evolved since the original 2009 rulemaking. Just as important, the no action alternative would preclude the more accurate accounting of carbon intensities for petroleum crude that would occur under the staff's proposal versus the "bright line" HCICO approach in the current regulation that is based on the grandfathered 2006 crude basket approach.

For the above reasons, staff has determined that a no-action alternative is not feasible and would not accomplish the same objectives as the staff's proposal at the same or lower costs.

2. Staff evaluated the following options for designating the potential electricity regulated parties:

    - Designate electric utilities as potential regulated parties for all EV charging.
    - Designate EV owners as potential regulated parties for electricity delivered to their vehicles.
    - Omit potential default regulated parties.

    When evaluating these alternatives, staff kept three goals in mind. The first goal was to keep the proposed language simple to avoid confusion in regulated party designation and maintain relevancy as the EV-charging market evolves in future years. The second goal was to limit the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties. The final goal was to maximize the number of credits captured and available for purchase.

    The first option – designate electric utilities as potential regulated parties for all EV charging – goes against the goal of maintaining relevancy as the EV charging market evolves in future years. Such designation cannot benefit potential charging equipment installers such as non-utility electric vehicle service providers, business owners, and EV fleet owners; therefore, this approach would discourage their efforts to establish the public and private charging networks which are critical to the future EV market.

    The second option – designate individual EV owners as potential regulated parties for electricity delivered to their vehicles – goes against the goal of limiting the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties. It is much more difficult to keep track of the credits from individual EV customers than from larger entities, such as the utilities.

The third option – designate a hierarchy of potential regulated parties without designating a default party – goes against the goal of maximizing the number of credits captured and available for purchase. Given the recordkeeping and other requirements in the LCFS regulation, there is a potential for significant amounts of credits to be “orphaned” or otherwise not captured and put into the credit trading market if the designated regulated party, such as a business owner with an onsite charger, fails to opt in. On the other hand, electric utilities have an inherent interest in being able to generate credits for electricity used for transportation. For this reason, among others, staff proposes to designate electric utilities as the default regulated party to ensure that credits are not orphaned.

3. Staff evaluated several alternative approaches for the treatment of HCICOs in the LCFS regulation:

   a. Current Approach with Amendments: Staff applies a screening mechanism to market crudes to identify crudes that are clearly non-HCICOs, then assigns a default CI value for crudes that are potential-HCICOs. Staff develops a process besides Method 2B to determine if potential-HCICOs are either non-HCICOs or HCICOs.

      Staff determined that this approach offered little benefit over the current approach.

   b. Hybrid California Average/Company-Specific Approach: The base deficit for individual companies is calculated the same as in the current regulation; however, individual companies only incur an incremental deficit if their own crude slate becomes more carbon-intensive over time relative to their crude slate refined in the baseline year.

      Although there is likely greater flexibility to purchase worldwide crude supplies for some companies than the current approach, this approach makes implementation more complicated due to the need for company-specific CI values each year. Staff does not have sufficient company-specific data to fully assess the impacts of this approach on individual oil companies.

   c. Company-Specific Approach: Each oil company would have distinct Lookup Table values and compliance targets for CARBOB and diesel, which are based on the crude slate refined by that company in California in the baseline year. Individual companies only incur an Incremental Deficit if their own crude slate becomes more carbon-intensive over time.

      As with the Hybrid Approach, this approach requires company-specific data that staff does not have. Furthermore, each oil company having its own CI values for

CARBOB and Ultra Low Sulfur Diesel (ULSD) in the market would be unnecessarily complex and discriminatory.

d. Worldwide Average Approach: This approach bases the average Lookup Table CI values for CARBOB and diesel and the compliance schedule on worldwide average crude oil production and refining emissions in the baseline year. An Incremental Deficit is applied to all companies if the worldwide average crude production and refining becomes more carbon intensive over time.

   Since crudes used by California refineries would have little, if any, impact on the CI value of the world average, this approach could result in significantly greater amounts of HCICO being used at California refineries because there is no effective incentive to avoid their use.

e. California Baseline Approach (Eliminate Consideration of HCICOs in the LCFS): All CARBOB and diesel would use the existing CI values in the Look Up Table. Regulated parties would only calculate and be subject to the Base Deficit for all CARBOB and diesel regardless of the crude oil used for refining. The Look-Up Table values for CARBOB and diesel would not be updated.

   This approach would eliminate the current HCICO provision. It does not account for, track, or mitigate increases in upstream emissions from crudes used by California refineries, and is therefore inconsistent with the lifecycle analysis basis of the LCFS. This approach could result in significantly greater amounts of HCICO being used at California refineries because there is no incentive to avoid their use.

I. INTRODUCTION

In this chapter, ARB staff provides a brief overview of the LCFS, information on the implementation of the LCFS program, and the regulatory process and actions taken to develop the staff's proposed amendments.

As noted, ARB staff is proposing various amendments to the LCFS regulation. The primary objectives of the amendments are to further clarify and enhance certain aspects of the regulation. These proposed amendments support the primary purpose of the LCFS, which is to reduce greenhouse gas (GHG) emissions by reducing the carbon intensity of transportation fuels used in California by 10 percent by 2020.

Additional information on the LCFS regulation and its underlying principles can be found in the 2009 staff report prepared for the adoption of the LCFS regulation.

A. Overview of the LCFS Regulation

On April 23, 2009, the Board approved the LCFS for adoption. The regulation became effective on January 12, 2010; additional provisions became effective on April 15, 2010. The first year of the program, 2010, was intended solely as a reporting year (i.e., for regulated parties to begin acclimating to the recordkeeping, reporting, and other administrative provisions by using the LCFS Reporting Tool (LRT), filing demonstrations of pathways, etc.). Actual implementation of the carbon intensity requirements and compliance schedules began on January 1, 2011.

The LCFS establishes two sets of performance standards that regulated parties must meet each compliance year. One set of annual standards is for gasoline and the alternative fuels that substitute for gasoline. The second set of standards is for diesel fuel and its substitutes. Each set of standards (i.e., "compliance schedule") is set to achieve an average 10 percent reduction in the carbon intensity of the statewide mix of transportation fuels by 2020.

The LCFS is based on the premise that each fuel has a "lifecycle" GHG emission value; subjecting this lifecycle GHG rating to a declining standard for the transportation fuel pool in California would result in a decrease in the fuel's lifecycle GHG levels. This lifecycle assessment (LCA) represents the GHG emissions associated with the production, transportation, and use of a given fuel in motor vehicles. The LCA includes direct emissions associated with producing, transporting, and using the fuels, as well as significant indirect effects on GHG emissions, such as changes in land use for some biofuels and other effects.

The LCFS standards are expressed in terms of the "carbon intensity" of gasoline and diesel fuel and their substitutes. Depending on the circumstances, GHG emissions from each step can include carbon dioxide (CO_2), methane, nitrous oxide (N_2O), and other GHG contributors. Moreover, the overall GHG contribution from each particular step is a function of the energy that the fuel contains. Thus, carbon intensity is expressed in terms of grams of CO_2 equivalent per megajoule (g CO_2e/MJ).

Fuels Included in the LCFS

The LCFS applies, either on a compulsory or opt-in basis, to most types of fuels used for transportation in California, including:

- California reformulated gasoline;
- California ultra low sulfur diesel fuel;
- Compressed or liquefied natural gas;
- Electricity;
- Compressed or liquefied hydrogen;
- Any fuel blend containing hydrogen;
- Any fuel blend containing greater than 10 percent ethanol by volume;
- Any fuel blend containing biomass-based diesel;
- Neat denatured ethanol;
- Neat biomass-based diesel; and
- Any other liquid or non-liquid fuel not otherwise exempted from the regulation.

Fuel Pool Carbon Intensity Standards

The LCFS achieves GHG emission reductions by incrementally reducing the allowable carbon intensity of transportation fuel used in California. The LCFS does not limit the carbon intensity of individual batches of fuels, but it does require regulated parties to comply with an annual standard for the transportation fuel pool they provide. As noted, this annual standard is expressed as carbon intensity in units of g CO_2e/MJ. The allowable carbon intensity of transportation fuels decreases each year, starting in 2011, until the carbon intensities of gasoline and diesel transportation fuels (and their substitutes) in 2020 are each reduced by 10 percent relative to 2010. Gasoline and diesel follow similar carbon-intensity reduction curves from 2011 through 2020 and beyond.

A graphical representation of the compliance schedules is presented in Figures 1 and 2. Table 1 shows the compliance schedules for gasoline and diesel fuel.

Figure 1

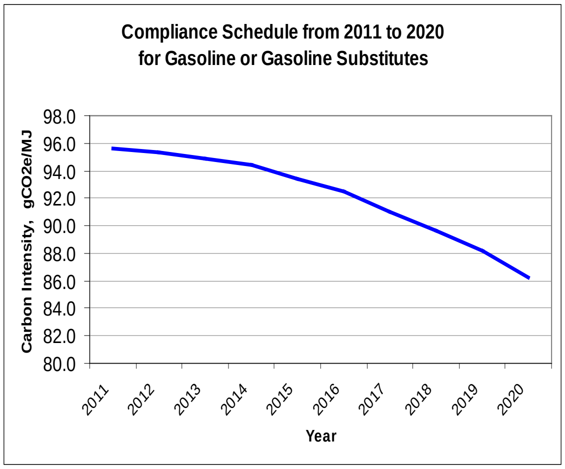

Figure 2

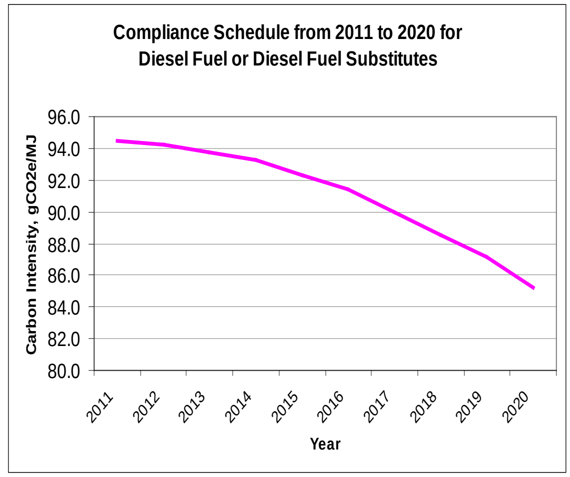

Table 1
LCFS Compliance Schedule

Year	Carbon Intensity for Gasoline and Fuels Substituting for Gasoline (g/MJ)	Gasoline and Fuels Substituting for Gasoline % Reduction	Carbon Intensity for Diesel and Fuels Substituting for Diesel (g/MJ)	Diesel and Fuels Substituting for Diesel % Reduction
2010	Reporting Only			
2011	95.61	0.25%	94.47	0.25%
2012	95.37	0.5%	94.24	0.5%
2013	94.89	1.0%	93.76	1.0%
2014	94.41	1.5%	93.29	1.5%
2015	93.45	2.5%	92.34	2.5%
2016	92.50	3.5%	91.40	3.5%
2017	91.06	5.0%	89.97	5.0%
2018	89.62	6.5%	88.55	6.5%
2019	88.18	8.0%	87.13	8.0%
2020 and subsequent years	86.27	10.0%	85.24	10.0%

Under the LCFS, the carbon intensity for alternative fuels (biofuels, natural gas, hydrogen, electricity) would be judged against either the gasoline or diesel carbon intensity standards, depending on whether the alternative fuel is used for light- or medium-duty vehicles or for heavy-duty vehicles, as specified in the regulation. In each year, the carbon intensity of each fuel is compared to the LCFS standard for that year.

Fuels that have carbon intensity levels below the standard generate credits. Fuels with carbon intensity above the standard create deficits. To comply with the LCFS for a given year, a regulated party must show that its banked total amount of credits equal or exceed the deficits incurred. Credits can be banked or sold to other regulated parties.

Determination of Carbon Intensity Values

The carbon intensity values represent the currency upon which the LCFS is based. The carbon intensity is determined in two parts. The first part represents the direct GHG emissions associated with producing, transporting, and using the fuel. This involves determining the amount of GHG emissions emitted per unit of energy for each of the steps in the fuel pathway. For example, these steps may involve the following for the production of ethanol:

- Farming practices (e.g., frequency and type of fertilizer used).
- Crop yields.
- Harvesting of the crop.
- Collection and transportation of the crop.
- Type of fuel production process.
- Fuel used in the production process (e.g. coal/CNG/biomass).
- Energy efficiency of the production process.
- The value of the co-products generated (e.g. distillers grain).
- Transport and distribution of the fuel.
- Combustion of the fuel in vehicles.

The second part considers any other significant effects, both direct and indirect, that are caused by the change in land use or other market-mediated effects. For some crop-based biofuels, staff has identified land-use change as a significant source of additional GHG emissions. No other significant indirect effects that result in large GHG emissions have been identified that would substantially affect the LCFS framework for reducing the carbon intensity of transportation fuels.

A more complete description of how the LCFS regulation is designed to work, as well as its underlying scientific and economic principles, can be found in the initial and final statements of reasons for the original 2009 rulemaking.[11]

B. Implementation Status of the LCFS Program

Since the LCFS was approved by the Board in April 2009, staff undertook several collaborations with stakeholders to help ensure the smooth launch of the program. First, staff convened an Expert Workgroup to compile and assess subsequent developments in the field of indirect effects analysis. The Expert Workgroup provided

[11] See www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf, www.arb.ca.gov/regact/2009/lcfs09/lcfsisor2.pdf, and www.arb.ca.gov/regact/2009/lcfs09/lcfsfsor.pdf.

recommendations on how best to incorporate such developments into the next iteration of the LCFS regulation. These efforts have helped focus staff's work on updating the indirect land-use change (iLUC) carbon-intensity values, which as noted below, will be proposed in a 2012 rulemaking after that work has been completed. Second, the staff convened a working group to evaluate developments in the field of sustainability. While it is unclear at this time whether the final deliverable of that ongoing effort will be regulatory or advisory in nature, the important work being conducted by that working group will help inform future versions of the LCFS. Third, as discussed in more detail later in this chapter, staff convened the LCFS Advisory Panel in early 2011. While the mandate of this panel is to evaluate and advise staff on high-level policies related to the LCFS, several of those evaluations helped inform the changes that staff is proposing in this Staff Report.

As noted, implementation of the compliance schedules and carbon intensity requirements began on January 1, 2011. Since early 2010, the LCFS has mandated that all regulated parties report required data on a quarterly and annual basis. To facilitate the electronic reporting of vast amounts of transactional data, ARB staff developed an on-line LCFS Reporting Tool (LRT) for the reporting of fuel volumes and other data to the State. The LRT is a secure, web-based data collection and report generation application designed to accommodate the submittals of all required information and help regulated parties meet the reporting requirements of the LCFS.

The LRT has been operational since early 2010 and has been used by regulated parties in its full production mode since December 2010. The LRT is readily accessible for electronic reporting by all regulated parties.[12] To date, a total of 70 entities have registered as regulated parties and have used the LRT exclusively for reporting during 2010 and the first quarter of 2011. These regulated parties have used the LRT for both manual fuel-transaction data entry via the user interface and through XML data file upload submission. Because the LRT has been the only means regulated parties have used for LCFS reporting, it has become the *de facto* method for electronic reporting.

Based on staff's review of reported first quarter 2011 data, it appears that regulated parties are able to generate substantial LCFS credits at this early stage of the program. During the first quarter of 2011, regulated parties reported generating about 225,000 metric tons of LCFS credits. On the other hand, regulated parties reported incurring about 150,000 metric tons of LCFS deficits. Additional results from staff's review of first quarter 2011 reports from the LRT are shown in Appendix B.

A healthy LCFS program depends on having a robust credit market and participants with confidence in a market that has clarity, certainty, transparency and accountability. Despite the number of credits generated in first quarter 2011, staff has determined that additional clarity and improvements to certain aspects of the regulation are needed to ensure an even more successful implementation of the program.

[12] See www.arb.ca.gov/lcfsrt.

To this end, the proposal's inclusion of specific opt-in/opt-out procedures, as well as enhancements to the biofuel and electricity regulated-party provisions, should increase both participation in the LCFS program and the generation of LCFS credits. Similarly, the proposal's credit trading provisions will provide certainty, clarity, transparency, and accountability to credit transactions, thereby increasing confidence in the credit market. Further, the proposal's certification procedure for taking action on Method 2A/2B submittals, without invoking a full rulemaking process, is expected to encourage further innovations that reduce carbon intensities. This, in turn, should help widen the range of biofuels and alternative fuels available for regulated parties to choose for their transportation fuel pools. Finally, the proposed update to the EER values and the HCICO refinements will help ensure that the regulation reflects the most up-to-date information and accounting/screening techniques.

C. Development Process for the Proposed Amendments

During the rulemaking process, ARB staff conducted three public workshops, several workgroup meetings, and numerous meetings with individual stakeholders to discuss the proposed amendments and address various concerns that were raised. ARB staff provided ample opportunities for stakeholders to comment on and present information about the proposed amendments. Meeting attendees included transportation fuel providers and importers, environmental groups, academia, and other interested persons. These individuals participated both by reviewing draft regulations and supporting documentation, providing data, and participating in workgroup meetings.

As noted, ARB staff established a number of workgroups, including the electricity, crude oil screening, and LCFS Reporting Tool workgroups, to address topic-specific concerns and suggested improvements raised by stakeholders during the rulemaking process.[13] Table 2 on the following page lists dates for the meetings that were held to apprise the public about the proposed amendments and other related developments.

[13] See http://www.arb.ca.gov/fuels/lcfs/workgroups/workgroups.htm for a compilation of the workgroups convened by ARB staff and the materials presented to and discussed with the workgroups.

Table 2: LCFS Workshop/Workgroup and Public Outreach Meetings

Meeting	Date	Location	Time
LCFS Proposed Amendments Public Workshops			
First Public Workshop	July 22, 2011	Cal/EPA Building, Coastal Hearing Room	9:00 a.m.
Second Public Workshop	September 14, 2011	Cal/EPA Building, Sierra Hearing Room	1:00 p.m.
Third Public Workshop	October 14, 2011	Cal/EPA Building, Sierra Hearing Room	1:00 p.m.
LCFS Electricity Workgroup (EWG) Meetings			
EWG Meeting	July 14, 2010	Cal/EPA Building, Conference Room 610	1:00 p.m.
EWG Meeting	October 26, 2010	Cal/EPA Building, Conference Room 610	1:00 p.m.
EWG Meeting	July 11, 2011	Cal/EPA Building, Conference Room 610	2:00 p.m.
LCFS High Carbon Intensity Crude Oil (HCICO) Screening Workgroup Meetings			
HCICO Workgroup Meeting	March 29, 2010	Cal/EPA Building, Conference Room 620	12:00 p.m.
HCICO Workgroup Meeting	May 6, 2010	Cal/EPA Building, Conference Room 620	9:00 a.m.
HCICO Workgroup Meeting	June 16, 2010	Cal/EPA Building, Conference Room 620	12:30 p.m.
HCICO Workgroup Meeting	July 14, 2010	Cal/EPA Building, Conference Room 610	3:30 p.m.
HCICO Workgroup Meeting	September 9, 2010	Cal/EPA Building, Conference Room 620	9:00 a.m.
HCICO Workgroup Meeting	February 17, 2011	Cal/EPA Building, Conference Room 620	9:00 a.m.

Over 7,100 individuals or companies were notified for each workshop/hearing. Notices for the public meetings were posted to ARB's LCFS websites (informational portal and public meetings/workshops) and e-mailed to subscribers of the "LCFS" list serve. The public workshops were webcast live whenever possible. In addition, ARB staff participated in numerous stakeholder meetings, presenting information on the implementation of the current regulation and the proposed amendments.

To increase public participation and enhance the information flow between ARB and interested parties, staff created the LCFS informational portal website (http://www.arb.ca.gov/fuels/lcfs/lcfs.htm). Since that time, staff has consistently made available online materials related to this rulemaking, including meeting presentations and draft regulatory language. The website has also provided background information on the LCFS, workshop and meeting notices and materials; other GHG related information; and links to other websites with related information.

Beyond the public and workgroup meetings noted above, staff's outreach efforts also included numerous personal contacts via telephone, electronic mail, regular mail, surveys, facility visits, and individual meetings with interested parties. These contacts included regulated parties, transportation fuel providers, marketers, importers, environmental, community, public health organizations, and other entities.

As noted previously, ARB staff also worked in parallel with the LCFS Advisory Panel. Its mandate is to assist ARB staff in reviewing specific aspects of the LCFS program's implementation; staff is to present the results of its two program reviews, with the Advisory Panel's input, to the Board by January 1, 2012 and January 1, 2015.

The staff's work with the Advisory Panel is ongoing. Because the Advisory Panel's purview generally covers high-level policy topics, it was not an appropriate forum for discussing technical details and minutiae in the LCFS regulation. Nevertheless, the discussions with the Advisory Panel were helpful in focusing staff's work to refine the proposal's changes to the regulatory text in a number of areas.

Finally, it should be noted that the proposal does not reflect the staff's ongoing work to update the indirect land-use change analysis (iLUC),[14] which was considered too preliminary at the time of this Staff Report's release to support a proposed amendment to the indirect carbon intensity values. This ongoing work is expected to be completed during the latter half of 2012, at which time the staff expects to propose regulatory amendments, if appropriate, to reflect the completed update.[15]

[14] See Chapter IV, section C, of the 2009 LCFS staff report (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf) at IV-16 through IV-48 for a general discussion of iLUC analysis. The current work is evaluating advancements in the iLUC analysis for corn ethanol, sugarcane ethanol, and soybean biodiesel.

[15] See http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm for presentations and materials discussed to date related to the iLUC work.

II. NEED FOR PROPOSED AMENDMENTS

As noted, the primary objectives of the proposed amendments are to clarify, streamline, and enhance certain provisions of the regulation. It should be emphasized that the proposal involves refining and improving certain aspects of the regulation and that the vast majority of the regulation remains unchanged by this proposal. Therefore, this ISOR builds on the comprehensive and extensive work that was done in support of the original 2009 LCFS rulemaking,[16] which generally remains applicable to this proposal, and this ISOR addresses only the proposal's incremental changes.

Staff developed these proposed amendments to support the overall purpose of the LCFS. The proposed amendments address several aspects of the regulation, including: reporting requirements, credit trading, regulated parties, opt-in and opt-out provisions, definitions, and other clarifying language. A summary description of each of the proposed amendments is provided in Chapter IV, Proposed Amendments.

After the Board approved the LCFS for adoption on April 23, 2009, the regulation entered into full effect on April 15, 2010. Implementation of the carbon intensity reduction requirements and compliance schedules began on January 1, 2011. As noted, implementation of the LCFS has generally been without significant issues. However, as with most complex regulations, there is always room to improve the LCFS.

There are several factors driving the staff's proposed amendments. First, based on stakeholder comments received in the original 2009 rulemaking, the Board directed staff in Resolution 09-31 to consider revisions to the regulation in a number of specific areas. These included updates to the Energy Economy Ratios (EERs), conversion of Method 2A/2B reviews into a certification process, and a reevaluation of the electricity regulated-party provisions. Second, staff solicited and encouraged feedback from regulated parties and other stakeholders throughout the LCFS' implementation. This feedback directly informed the staff's refinements contained in this proposal. Finally, staff conducted internal reviews of lessons learned since implementation began. For example, these reviews lead to the proposal to enhance the regulated party definitions and provisions, credit trading provisions, and opt-in/opt-out procedures.

With the above drivers, staff was able to identify specific areas of the regulation for clarification and other improvements. These proposed improvements are expected to better ensure the successful implementation of the LCFS program. Beyond this proposal, staff will continue to monitor implementation of the LCFS and developments in fields, such as credit trading, land use change analysis, and high carbon intensity crudes, to help shape further refinements in future iterations of the LCFS.

[16] See the initial statement of reasons (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf and http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor2.pdf) and final statement of reasons (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsfsor.pdf) for the original 2009 LCFS rulemaking, all of which are incorporated herein by reference.

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III. TECHNOLOGY ASSESSMENT

The staff report for the original LCFS rulemaking clearly showed the basic regulation to be technologically feasible.[17] Accordingly, this chapter discusses the technical feasibility of meeting the proposed amendments. Because there are no new fuel pathways and no new scientific modeling in this proposal, the amendments do not require regulated parties to use new technologies in order to comply. Staff has identified no technological barriers that would prevent regulated parties from meeting the proposed changes. As noted, the proposal is generally aimed at streamlining the LCFS, increasing its flexibility, and making the program implementation operate more smoothly. The following summarizes the technological feasibility of the major proposed changes; additional details are provided in Chapter IV, Proposed Amendments.

Opt-In/Opt-Out and Enhanced Regulated Party Provisions

The current regulation allows for regulated parties of low CI fuels to opt into the program. However, there are no provisions explaining how opting in is to be accomplished. The staff's proposed changes are intended to address this and bring more voluntary participants into the program. The proposed changes will clarify the circumstances under which existing participants would be designated as the regulated party for a specific volume of fuel.

There are no complex technologies required for a regulated party to opt in. Under the proposal, opting into the LCFS program simply requires registration as a regulated party through the LRT online program. As noted previously, the LRT is readily accessible through ARB's website (https://ssl.arb.ca.gov/lcfsrt/Login.aspx). Regulated parties can use a standard web browser to access the LRT, such as Firefox®, Internet Explorer®, Safari®, Opera®, and other popular browsers. For those eligible, opting out of the regulation would only require that email and hardcopy notices be submitted to ARB staff for confirmation. Based on these considerations, this proposed amendment was found to be technologically feasible.

Mandatory LRT Use

As noted, the LRT has become the *de facto* method for regulated parties to electronically submit their required quarterly and annual reports. ARB staff is not aware of any regulated party's inability to access and use the LRT through ARB's website.

The next generation LRT is under development. Currently, known as the LCFS Central Information System (L-CIS), it will be a more interactive workspace for regulated parties to meet their regulatory needs. The system will be designed to incorporate Method 2A/2B submittals, credit transactions, and voluntary biorefinery and opt-in fuel producer registrations. Until the L-CIS is operational, regulated parties can provide the

[17] See Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the Low Carbon Fuel Standard, Vol. I (March 5, 2009), at ES-7 and III-1 through III-22.

required information via electronic or regular mail submittals; the proposal does not refer to or otherwise rely on the existence of the L-CIS.

Method 2A/2B Certifications

The proposal to convert the current rulemaking process for approving Method 2A/2B submittals into a certification process does not involve any technological requirements other than the requirement for applications to be electronically submitted. Such submittals are readily achieved through the use of standard email programs or by submitting an application package on a compact disk or other electronic media.

Credit Trading

The information required to be reported under the proposed amendments will, in the short term, be processed manually by ARB staff. Upon receipt of the required information (via electronic or regular mail submittal), staff will process the information and manually input the relevant transactional data into the LRT accounts for both buyers and sellers. As noted, the next-generation LRT (L-CIS) will be designed to handle this transactional information electronically and automatically, but there are no requirements in the proposed amendments that refer to or otherwise rely on the L-CIS.

Electricity Regulated Party Provisions

The proposal specifies requirements for various entities to qualify for electricity credits. Depending on the circumstances, these requirements may include one or more of the following:

- Use all credit proceeds as direct benefits for current electric vehicle (EV) customers.
- Provide rate options that encourage off-peak-charging and minimize adverse impacts to the electric grid.
- Educate the public on the benefits of EV transportation through outreach efforts such as holding public meetings, providing EV dealership flyers, utility customer bill inserts, radio or television advertisements, and publishing EV-relevant webpage content.
- Report annually a summary of the above efforts, as well as an accounting of the number of EVs known to be operating in the service territory.

The above list does not impose requirements involving any technologies above and beyond standard telecommunications, word processing, and internet/web publishing programs that are readily accessible to the general public and businesses.

HCICO

The HCICO provisions in the proposal simply dictate how a regulated party, with HCICO-derived fuel in its fuel pool, would account for that HCICO when calculating its credits and deficits. There are no special technologies required to conduct the proposed changes to the crude oil CI accounting. Typically, such regulated parties would be a small group of petroleum refineries and marketers. Thus, the HCICO provisions basically entail nothing more complicated than careful recordkeeping, reporting, and accounting, which refineries presumably do already using currently available accounting software. While regulated parties may need to better understand the origins of their HCICO-derived fuels, staff is unaware of any special technologies that would be required for a regulated party to perform these actions.

EER Updates

The energy economy ratio (EER) refers to the unitless multiplier that is used to account for differences in energy efficiency among different types of fuels and vehicles. The EER is defined as the ratio of the number of miles driven per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel. For purposes of the LCFS, the reference fuel is gasoline for light- and medium-duty vehicles, and diesel for heavy-duty vehicles. Thus, the EER for light-duty vehicles for a given fuel is defined as the ratio of the miles driven per energy consumed for that fuel to the miles driven per energy consumed for a comparable vehicle using gasoline. Therefore, the EER for gasoline is always 1.0 for light- and medium-duty gasoline-powered vehicles; similarly, the EER for diesel is always 1.0 for diesel-fueled heavy-duty vehicles.

In this proposal, staff is updating the EERs for a number of alternative fuels, including battery electric vehicles (BEV), plug-in hybrid electric vehicles (PHEV), fuel cell vehicles, and heavy-duty compressed natural gas (CNG) or liquefied natural gas (LNG) vehicles.[18] In the original 2009 rulemaking, the data for these fuels were relatively limited.[19] Since then, a number of vehicles have come into the market using these fuels. This influx of new alternative-fueled vehicles has allowed staff to use more real-world, fuel-economy data for those vehicles to update their EERs. This is explained in more detail in Chapter IV, Proposed Amendments.

Because staff's proposal is based on actual alternative-fueled vehicles that are commercially available, the proposed changes to the EERs are clearly technologically feasible. Moreover, there are no technologies required for regulated parties to meet these updated EER values; the values are simply inputs in the credit/deficit calculations specified in the regulation.[20] Because the LCFS does not regulate the EERs but simply lists them, there are no technologies required to be used by vehicle or engine manufacturers.

[18] These EERs can be found in Cal. Code Regs., tit. 17,§ 95485(a)(3), Table 5.
[19] See Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the Low Carbon Fuel Standard, Vol. I (March 5, 2009), at ES-18.
[20] See Cal. Code Regs., tit. 17,§ 95485(a)(3)(A) and (B).

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IV. PROPOSED AMENDMENTS

In this chapter, we provide a discussion of each of the major proposed amendments. All section references are to the LCFS regulation (13 CCR 95480-95490) unless otherwise noted.

A. Opt-In and Opt-Out Provisions

Section 95480.1(b) currently identifies specific low-CI fuels that are exempt from the LCFS program. Although the language allows providers of these fuels to opt into the program to generate credits, it does not specify a procedure for voluntarily opting in or opting out. Consequently, there are a number of providers of biogas and other exempted, low-CI fuels (i.e., those that already meet the 2020 CI standards) that want to opt into the LCFS but are reluctant to do so at this time; among the reasons they cite for their reluctance is the lack of a specified opt-in/opt-out procedure.

In addition, there are a number of out-of-state producers and intermediates that have expressed a similar desire to voluntarily opt into the regulation in order to become regulated parties. However, the existing regulatory text does not allow such out-of-state entities to become regulated parties due to jurisdictional concerns. Because such producers are not currently able to become regulated parties, they must sell their fuels without the ability to retain the compliance obligation (and hence retain the credits); if the product is sold to an importer to California, that importer would be designated the regulated party under the existing rule. If these producers and intermediates are allowed to voluntarily enter the LCFS program as regulated parties, they would be able to sell their fuels and retain all or part of the credits generated from their low-CI fuels.

Accordingly, staff is proposing changes that would address these concerns. First, staff proposes to include a new section 95480.2, which would identify and establish specific criteria for voluntarily entering the LCFS program (i.e., criteria that would apply to persons wishing to opt into the program). In addition to the fuel providers specified in section 95480.1(b), this new section would allow out-of-state producers of oxygenate (e.g., ethanol) or biomass-based diesel to opt into the program. Further, the new section would allow intermediate entities downstream of the out-of-state producer to also opt into the program under prescribed conditions. Finally, this new section would allow for gas suppliers to opt into the program, under specified conditions, in lieu of California compressed natural gas (CNG) fueling station owners, if such station owners have not otherwise elected to opt into the program. Allowing the gas suppliers to opt into the program under the specified conditions will help ensure that potential LCFS credits are not "orphaned" if the fueling station owners choose not to opt into the program.

Second, staff proposes a new section 95480.3, which would specify the actual procedure for opting into and out of the LCFS program. This procedure would be available for those persons who are qualified to opt in under new section 95480.2.

Opting in would simply require a qualified person to register as the regulated party for the fuel of interest.

This new section 95480.3 would also specify the options available for the opt-in regulated party to select the applicable CI value for its fuel. Basically, in addition to the standard options (Methods 1, 2A, and 2B) that are available to other regulated parties, opt-in regulated parties for low-CI fuels subject to section 95480.1(b) would have a third option of choosing the 2020 endpoint CI values for the gasoline or diesel compliance schedules. In other words, if an opt-in regulated party for CNG, for example, does not want to choose Method 1 (or there are no applicable CI values in the Lookup Table), and it wants to avoid submitting a Method 2A/2B application for a new/modified fuel pathway, the regulated party can choose either the 2020 CI target for gasoline (86.27 gCO2e/MJ) or diesel (85.24 gCO2e/MJ), whichever applies. This is because the fuels, including CNG, which are subject to section 95480.1(b) are presumed to already meet the 2020 CI standards.

As noted, new section 95480.3 would specify the procedure for opting out. The proposed procedure would specify 90-day pre-opt out notification, verification that the opt-out occurred on that date, and post-op-out notification and reporting requirements. The proposal would also require recordkeeping consistent with the recordkeeping requirements already specified in the regulation for all regulated parties.

Third, the expansion of potential opt-in entities, especially for qualified intermediates, raises the possibility of multiple parties inadvertently registering and reporting themselves as the regulated party for the same volume of fuel. Therefore, staff proposes a new section 95480.4 that would establish a clear procedure for the Executive Officer (EO) to use in determining which party can validly claim to be the regulated party in that situation. Essentially, the proposal would look first at any contracts between the parties of interest to see if the agreements identify the proper regulated party. In the absence of clear contract language, the EO would then look at the regulatory language and apply the priority scheme contained therein. Finally, in case neither of these approaches works, the proposal would assign regulated party status based on a specified default. While the EO's determination is underway, any credits subject to multiple claims of regulated party status will be held in escrow for a maximum of 30 business days.

Thus, for fuels produced outside California, the regulatory text would effectively assign initial regulated party status in the following order of priority (unless written contracts between the parties stipulate otherwise):

1. Out-of-state producer (if the producer opts in);
2. Intermediate entity downstream of the out-of-state producer (if the producer transfers compliance obligation to the intermediate and other requirements in 95480.3 are met); and
3. Importer (if neither 1 nor 2 applies).

Finally, staff proposes a new section 95480.5 that would make it clear that registration as a regulated party (in this case, as an opt-in regulated party) would establish that person's consent to be subject to California jurisdiction. This new section would also establish a person's consent to be subject to California jurisdiction if the person receives proceeds from a credit transaction.

B. Enhanced Regulated Party

The existing LCFS regulation places compliance obligations initially on California fuel producers and importers. Section 95484 of the regulation specifies the criteria under which a person would be deemed a regulated party for each particular fuel and how the responsibility for complying with the LCFS can be transferred. As currently worded, the regulation provides for the transfer of compliance obligation to flow "downstream" from the initial regulated party; it does not permit the compliance obligation to flow "upstream" to intermediates and the out-of-state producer.

As noted above in "Opt-In and Opt-Out Provisions," staff is proposing changes that would allow out-of-state producers to voluntarily enter the LCFS program by becoming the initial regulated party. Consistent with this proposal, staff is also proposing to change the definition of "producer" so that it also encompasses out-of-state producers (the current definition includes only California-based producers).

Further, based on stakeholder comments received,[21,22] staff is proposing revisions to the definition of "importer" to include, as potential initial regulated parties, those entities that own title to a product at the point the equipment has entered California. The existing regulation confers initial regulated party status to importers if those persons own title to the fuel when it is received at the "import facility," so this proposed change would impart the regulated party status on the person who owns the product in the transportation equipment that held or carried the product, when it entered California. Staff proposes to delete the definition of "import facility" since the definition of "importer" no longer references "import facility."

C. Method 2A/2B Certification

When the Board approved the LCFS in April 2009, the regulation contained both fuel pathway Lookup Tables and a formal process for adding pathways submitted by stakeholders to those tables. The Lookup Tables (Tables 6 and 7, section 95486(b)(1)) house the carbon intensities of the fuel pathways that the Board approved. Section 95486(c) and (d) establish the procedures regulated parties and other entities must follow in order to add new pathways to the Lookup Tables. Those procedures consist of a formal application process in which the applicant calculates a pathway

[21] Robert Whiteman, POET Ethanol Products, July 29, 2011. Comment letter to ARB providing specific information about how liquid biofuels are currently being delivered into California.
[22] Jessica Wiechman, Renewable Products Marketing Group, Inc. (RPMG), August 5, 2011. Comment letter to ARB regarding Midwest biofuel industry.

carbon intensity value, using the California Greenhouse gases, Regulated Emissions, and Energy use in Transportation (CA-GREET) model, and provides ARB staff with sufficient supporting documentation to recommend the proposed pathway carbon intensity for approval by the EO.

Because the Lookup Tables are contained in the LCFS regulation, making changes to them (i.e., adding a new fuel pathway) would require a full rulemaking process pursuant to the Administrative Procedure Act (APA)[23].

As with most ARB rulemakings, the approval of new or modified fuel pathways for incorporation into the Lookup Tables would require an initial and final statement of reasons, at least one formal comment period (generally a 45-day period), and a public hearing. Substantive changes proposed after the start of the formal comment period would entail additional comment periods. Thus, a typical rulemaking would take from six to 12 months during the formal rulemaking phase. This doesn't include the approximate 30 to 90 days of working with an applicant, before the formal comment period begins, to prepare the application. Based on the potential efficiency gains and in recognition that the activities to process and evaluate Method 2A/2B applications are becoming more routine, the Board directed staff under Resolution 09-31 to investigate the feasibility of converting the rulemaking process for the approval of new or modified pathways into a more streamlined certification process.

While the certification program described in this Chapter was under development, the Board issued Resolution 10-49, which directed staff to develop a process whereby Method 2A and 2B applicants could use their proposed pathway CIs once staff recommended them for approval. Approval recommendations are issued well before the applications can be heard before the EO. Accordingly, guidance clarifying this policy was issued in December of 2010 in the form of LCFS Regulatory Advisory 10-04. Under that Advisory, Method 2A and 2B applicants are able to use their proposed CIs as soon as staff recommends them for approval and posts them to the LCFS web site.

Regulatory Advisory 10-04 allows applicants to temporarily use the CIs for which they apply while the rulemaking process is underway, but does not expedite the final approval process. Nor does it alleviate the substantial ARB staff workload associated with the regulatory change process. Importantly, it also does not fulfill the Resolution 09-31 directive to develop a certification program. As such, the Regulatory Advisory 10-04 process amounts only to a temporary measure.

Proposed Certification Process

This section provides a brief, plain English summary of the major elements of the proposed certification process. Because the certification process itself is highly detailed and comprehensive, the reader is directed to Appendix A (Proposed Regulation Order) for exact details on the proposed regulatory text.

[23] Government Code section 11340 et seq.

Under the existing regulation, a regulated party can use a CI value from the Lookup Tables that applies to that person's fuel pathway (subject to approval by the EO). Alternatively, the regulated party can submit a Method 2A/2B application for EO certification of the new or modified pathway. As part of the approval process, the EO would issue an Executive Order for the fuel pathway covered by the certification. The Executive Order would apply only to the applicant and its certified fuel pathway(s).

1. Application Submission Requirements

The staff's proposal would require applications, in order to be deemed complete, to contain extensive and detailed information about the applicant's proposed fuel pathway. As noted, the detailed information that would be required in the submittal is specified in the proposed regulatory text.[24] This high level of detail is derived from ARB staff's experience with the Method 2A/2B review process to date. Based on that experience, the staff's proposal specifies a level of detail in the required information that staff believes is necessary for the EO to make the determination that the application is based on robust, scientifically defensible and credible information. Further, for Method 2A applications, the information is necessary for the EO to make the determination that the application represents an innovation that meets the regulation's substantiality requirements.

A primary concern in the application process is the protection from disclosure of confidential business information (CBI). On the other hand, this concern must be balanced with the need to maintain transparency and give the public a meaningful opportunity for comment and review of the proposed fuel pathway. To balance these concerns, the proposed application process would require the applicant to submit a fully detailed application, including all required information, for ARB staff's review. At the same time, the proposal would require the applicant to also submit a version of the application with the CBI redacted to the extent that would still allow for meaningful public review. The process would require applicants to clearly identify the specific information for which confidentiality is sought.

2. Application Evaluation Procedure

The proposal specifies that, within 30 calendar days after receiving an application designated by the applicant as a final, evaluation-ready copy, ARB staff will advise the applicant in writing that it is either complete or that specified additional information is required to make it complete. Within 30 calendar days from the request for additional information, ARB staff will again advise the applicant in writing that the application is either complete or that specified additional information is still required before it can be deemed complete. The proposal does not specify how many times this cycle can be repeated, but the application can be denied if staff determines that the required information is not forthcoming. Even if an application packet has been deemed complete, the proposal provides ARB staff with the ability to request additional

[24] See section 95486(f)(3)(C) of the proposed regulation order.

information and clarification, if needed, as staff's analysis of the application packet proceeds. This may be needed, for example, if staff's analysis of an application already deemed complete raises additional issues that need to be addressed.

The proposal specifies that the formal evaluation will last no more than 90 calendar days. Because each application is unique and may present unforeseen challenges, the proposal provides for the possibility of pausing staff's evaluation while staff works with the applicant to resolve such issues. This allows the evaluation process, once the issues have been resolved, to resume at about the point where it left off.

Under the staff's proposal, the evaluation of complete Method 2A and 2B applications will generally involve the following steps:

- Staff attempts to replicate the applicant's carbon intensity calculations;
- Staff attempts to replicate the energy consumption inputs to the carbon intensity calculations using the energy purchase and fuel production data in the application;
- Staff evaluates the production information submitted by the applicant for consistency, both with itself (internal consistency) and with every other item in the application (external consistency). Consistency is required in all areas, not only those that directly contribute to the calculation of the pathway carbon intensity; and
- Staff evaluates the documentary basis of all data and assumptions that are not verifiably derived from the energy consumption and fuel production data included in the application packet.

If any of the steps outlined above cannot be complete due to a discrepancy or other issue, the evaluation will be suspended until the discrepancy or issue can be resolved.

3. *Pathway-Specific Requirements*

The proposal provides for specific requirements that apply to certain types of pathways. These requirements will minimize the exercise of discretion in the evaluation of the applications in these categories and help assure consistent outcomes across different applicants.

a. Most fermentation-based pathways (e.g., corn ethanol) yield a co-product known as distillers grains with solubles (DGS), which the applicant may sell at varying levels of moisture content. Many fuel operations will vary DGS drying over time to reflect market conditions. In order to assure that all drying energy for different levels of DGS dryness are accounted for, applicants who sell DGS at more than one dryness level will be required to calculate their pathway CI (or CIs) using one of the following methods:

    i. General approach (most applicants): Calculate a single CI that reflects the maximum foreseeable production of fully and partially dried DGS, reflecting the total plant energy consumed while DGS is being dried at the maximum foreseeable rate. The applicant can average plant energy consumption on either a monthly or an annual basis. However, any ethanol associated with the production of dry or partially dry DGS, in excess of the quantities used to calculate the plant's pathway CI, cannot be sold in California under the approved pathway. For example, the approved CI may be based on drying 75 percent of the total DGS stream, calculated as an annual average. After the pathway has been approved, if 80 percent of the ethanol is dried in any given year, the ethanol associated with the production of 80 percent dry DGS cannot be sold in California under the approved CI. The approval issued by the EO will, in fact, include an operational condition stating that the production of dry or partially dry DGS shall never exceed the quantities on which the approved CI is based.

ii. Alternative approach: An applicant with a plant that has DGS dryers equipped with functional and accurate gas gauges may apply for separate CIs for each DGS dryness level. This is provided the applicant is able to accurately associate every gallon of ethanol produced with a specific DGS dryness level. Dryer gas gauge readings will be used to precisely calculate the drying energy consumed for each DGS dryness level. These energy consumption levels will be added to baseline (100 percent wet DGS) levels to calculate DGS-specific carbon intensities. The applicant must then demonstrate, to ARB staff's satisfaction, that each gallon of ethanol produced can be clearly associated with only one DGS dryness level. This association must be credible and accurate, even in plants with continuous DGS production that employ dryers that function in series.[25]

b. Although ARB encourages and is moving to fully account for agricultural practices aimed at reducing GHG emissions, accounting for these practices under the proposed Method 2 certification process is not yet straightforward. Reliable data, with sufficient geographic resolution, on the use of such practices is limited.

For example, it is currently difficult to determine how various planting and disking practices alter equipment use, chemical application rates, erosion, and decomposition of soil organic matter. In other cases, State-level data showing performance improvements over national averages may exist, but no indication of the variance in the data is available. A high variance may mean that the apparent difference isn't actually significantly different from zero. Even if the significance of an apparent difference can be confirmed, there is usually no way to determine farm-to-farm differences (i.e., there is no certainty that practices on the specific farms supplying feedstock to fuel producers seeking LCFS certification actually conform to the state-level averages). Finally, even in cases where farm-level GHG-benefits can be documented on the farms supplying feedstock to pathway applicants, most of the practices are easily reversible. Economic conditions could easily alter the extent to which reduced-emissions practices are maintained from year-to-year.

[25] When dryers are installed in series rather than singly or in parallel, a portion of the DGS stream exiting the first dryer enters a second dryer, where it becomes dry DGS. The portion of the stream that is diverted before it enters the second dryer becomes modified (or partially dry) DGS.

Until a process is developed whereby practices that reduce GHG-emissions are included in the calculated fuel pathway CIs, the Method 2 pathway development process can only credit pathways for low-emissions agricultural practices if:

i. scientifically sound data exist that demonstrate the claimed practices are in use on the specific farms that supply feedstock to the Method 2 applicant, and

ii. the applicant agrees to a process in which ARB can confirm that the beneficial practices remain in place for each crop cycle.

c. Certification applications for sugarcane pathways would need to be backed by verifiable third-party documentation. Acceptable forms of documentation include, but are not limited to, receipts for sales of surplus electricity, sales receipts from ethanol buyers, engineering studies produced by independent and well-established engineering firms, independent audit reports, and published research results. An area in which sugar cane ethanol producers may be able to improve their carbon intensities is by exporting electricity in excess of the 0.96 kWh/gallon of ethanol, which is the basis for the two lowest sugarcane ethanol CIs (66.40 and 58.40 gCO2e/MJ) ARB staff has assessed at this time. Any application claiming exports beyond this level must document that claim with, for example, receipts from the buyers of the surplus electricity, and sales receipts for all ethanol sold over the period covered by the electricity sales receipts. Third party audit and engineering reports may also suffice.

   Additional sugarcane-specific requirements are specified in the staff's proposed amendments. For example, the applicant would need to demonstrate that only the electricity generated from the bagasse associated with the cane used in the ethanol production was counted in the electrical export calculations (i.e., the bagasse from the cane that went to sugar production cannot be counted). Similarly, the electricity sold to the grid from the sugar production operation could not be counted in the calculation of the ethanol electricity export credit. Further, applications that claim credit for mechanical harvesting would need to be supported, with verifiable third-party documentation, that show mechanical harvesting is used on an ongoing basis on the plantations supplying sugarcane to the applicant's mills. This is necessary because a large proportion of plantations still do not employ mechanical harvesting.[26]

Additional carbon intensity determination provisions unrelated to the proposed certification program were also added to Section 95486(a). In 95486(a)(4), a provision

[26] See, for example, Alves de Aguiar, Daniel, Wagner Fernando da Silva, Bernardo Friedrich Theodor Rudorff, Marcos Adami, July 5-7, 2010, "Canasat Project: Monitoring The Sugarcane Harvest Type In The State Of São Paulo, Brazil." In: Wagner W., Székely, B. (eds.): ISPRS TC VII Symposium – 100 Years ISPRS, Vienna, Austria, July 5–7, 2010, IAPRS, Vol. XXXVIII, Part 7B. : http://www.isprs.org/proceedings/XXXVIII/part7/b/pdf/10_XXXVIII-part7B.pdf. The authors found that 50.9 percent of the harvested sugarcane area in the State of São Paulo was burned in 2008/09.

creating default carbon intensity values was added. These values—one for gasoline substitutes and one for diesel substitutes—could be used, with Executive Officer approval, in cases in which the actual carbon intensity cannot be determined. This provision was added to the regulation because carbon intensity defaults currently exist only in Regulatory Advisories 10-04 and 10-04a, both of which are set to expire.

A fuel's carbon intensity cannot be determined if:

- It's production facility cannot be identified, or
- It has neither been registered with Biofuel Producer Registration process, nor received a carbon intensity via the Method 2 process.

This section establishes a default of 99.4 gCO_2e/MJ (the Midwest average from the Lookup Table) for gasoline substitutes, and the current annual ULSD baseline carbon intensity for diesel substitutes

Provisions were also added to 95486(a)(2) and (3) clarifying the procedure by which carbon intensities are determined using the Method 1 process. These new provisions specify that Method 1 can only be used for fuels that are produced using a well-to-wheels production pathway that is substantially similar to the corresponding well-to-wheels pathway described in the pathway document on which an LCFS Lookup Table pathway is based. Although the current regulation accomplishes this, the degree to which the actual fuel pathway and the Lookup Table pathway must be similar may not be clear without reference to 95486(b) in which the pathway documents behind the Lookup Table pathways are referenced. The proposed new language provides full clarity on this point within 95486(a).

D. Credit Trading Provisions

A new section 95488 is proposed to the LCFS regulation to provide more detail on how credits and deficits will be tracked, and to specify the process to be used to acquire, bank, transfer, and retire credits. Furthermore, this section clarifies how a regulated party can use credits acquired in the first quarter of a year to meet a compliance obligation in the previous year. This section would also establish requirements relating to the public release of information concerning deficits and the generation, use and transfer of credits.

Moreover, staff is proposing a number of changes to section 95484(b) of the existing regulation, and proposes to relocate section 95484(b) to new section 95488(a). These changes do not alter the stringency of the LCFS or change a regulated party's compliance obligation. They modify the formulas used to demonstrate compliance, change some of the terminology used, and conform the provisions of section 95488(a) to the proposed provisions of section 95488(b) through (e).

Changes to Previous Section 95484(b)

Section 95484(b) of the existing regulation, which is now relocated to section 95488(a), specifies how to calculate a Credit Balance and how to use the Credit Balance to determine if an annual compliance obligation has been met. The existing rule reflects an approach where "net" credit balance is tracked through quarterly reporting, and compliance is achieved when a regulated party's credit balance is zero or positive at the end of an annual compliance period.

However, as staff investigated a more detailed system for banking and trading credits, they determined that an approach that clearly separates credit generation and tracking from deficit accounting was appropriate. Accordingly, staff proposes several changes to reflect such an approach. The proposed changes, which do not alter the stringency of the LCFS, include:

- A new formula to calculate a regulated party's annual compliance obligation.
- A revised formula to calculate a regulated party's credit balance.
- A provision specifying that a regulated party must retire credits equal to deficits to demonstrate it has met its annual compliance obligation.
- A revised method to determine a regulated party's credit to deficit ratio if the regulated party retires insufficient credits to meet its compliance obligation.

First, the proposal would define a new term—a regulated party's compliance obligation. The compliance obligation would be the sum of all deficits a regulated party generated in the current compliance period plus any deficits that were carried over from a previous period. The proposed approach is no more or less stringent than the existing rule.

Second, the proposal would modify the formula used to calculate credit balance. The revised formula would be based on credit generation and credit acquisition or credit transfer[27] only. Credit balance would be calculated as follows:

$$\textit{Credit Balance} = \textit{Sum of }(\textit{Credits}^{\,Gen} + \textit{Credits}^{\,Acquired}) - \textit{Sum of }(\textit{Credits}^{\,Retired} + \textit{Credits}^{\,Sold} + \textit{Credits}^{\,Exported})$$

where:

$\textit{Credits}^{\,Gen}$ are the total credits generated pursuant to section 95488;

$\textit{Credits}^{\,Acquired}$ are the total credits purchased or otherwise acquired, including carry back credits acquired pursuant to section 95488(b)(3);

[27] Transfers include credit retirement, the transfer of credits to other regulated parties, and the export of credits to other programs.

Credits ^{Sold} are the total credits sold or otherwise transferred;

Credits ^{Exported} are the total credits exported to programs outside the LCFS; and

Credits ^{Retired} are the total credits retired within the LCFS.

The term Credit Balance would be used to determine the total number of credits in a regulated party's credit account. This is the maximum number of credits that can be retired for compliance or, in the case of a proposed credit transfer, the maximum number of credits that can be transferred to another regulated party.

Third, the proposal would add a new section: "Compliance Demonstration." This section specifies that an regulated party must possess and have retired qualifying credits[28] equal to its deficits (as defined by its compliance obligation) by the time the regulated party submits its annual compliance report. The proposed approach is no more or less stringent than the existing rule. The compliance demonstration replaces the term "Credit Balance" currently used in section 95488(a)(2) to determine if deficits exist and must be carried over to the next compliance period.

Fourth, the proposal would establish a new formula to determine if a deficit can be carried over to the next compliance period without penalty. The proposed approach is no more or less stringent than the existing rule. A regulated party is required to retire credits equal to at least 90 percent of its compliance obligation in order to carry over deficits without penalty.

Finally, the proposal would modify some of the terms used in the Deficit Reconciliation section so that this section conforms to the changes made in the preceding subsections.

New Section 95488 - Banking, Transfer and Retirement of Credits

Earning and Using Transferrable Credits

Credits are generated under the LCFS program when the carbon intensity (CI) of a fuel or blendstock supplied for transportation use is below the annual gasoline or diesel standard. The amount of credit generated by fuels with CIs that are lower than the CI of the LCFS depends on both the CI of the fuel and the quantity that is supplied in California. Regulated parties use the LCFS Reporting Tool (LRT) to report the fuels they supply, and the LRT uses this information to calculate both the credits and deficits that are generated for each fuel type. Under the proposed approach, the amount of

[28] Qualifying credits must have been generated by a regulated party prior to the end of an annual compliance period. Credits which are generated in the first quarter of a year may not be retired to meet a previous year's compliance obligation.

credit generated would not be affected by the amount of deficits incurred by the same regulated party[29]. Deficits and credits would be tracked separately in the LCFS. For example, suppose a supplier provides fuel A, B, and C, and fuels A and B generate credits while fuel C generates a deficit. The total credits generated is the sum of credits from fuel A and fuel B, regardless of the deficits generated from fuel C. Figure 3 illustrates how credits are generated by the successful, timely submission of a quarterly report.

Figure 3: Summary of Quarterly Report Showing Credits and Deficit Generated as a Result of Supplying Ethanol to California

Submit Quarterly Report

Organization: Not Applicable **Reporting Period: Quarter 1 , 2011** **Status: Open**

Quarterly Fuel Details

Transaction Details	Fuel Name	Fuel Pathway Code	CI (g/MJ)	EER	Total Obligated Amount	Unit	Credits (MT)	Deficits (MT)	Incremental Deficit (MT)	Fuel Application
Goto Details	Ethanol from Corn	ETHC031	83.70	1	45,454,345	gal	44,126	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC028	91.70	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC027	88.50	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC026	88.50	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC025	92.40	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC008	90.10	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC004	98.40	1	444,334	gal	0	101	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Sorghum	ETHG006	84.36	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Sorghum	ETHG002	85.81	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles

Total quarterly credits generated and banked* **Total Credits/Deficits Generated (MT): 44,025**

***** The total number of credits banked and available for trade is determined from the sum of all credits generated from the supply of fuels that exceed the performance of the standard.

In Figure 3, a regulated party has submitted a quarterly status report showing the supply of two ethanol fuels. In the LRT, a quarterly summary page containing an overview of the reported information is displayed to the user. The summary page shows all credits

[29] Staff had considered using the net credits to limit the amount of credit a regulated party could bank or transfer or trade. However, after reviewing the existing LCFS regulation, it was determined that the concept of limiting the number of credits that could be banked or traded to the net credits was not consistent with the adopted regulation, and that maintaining a separate accounting process for credits and deficits was preferable.

calculated from the supply of fuel below the standard in the column labeled "Credits (MT)." Similarly, a column called "Deficits (MT)" contains all deficits associated with fuels above the standard.

On a quarterly basis, upon the successful, timely submission of a report, a total value representing the sum of all credits and a total value representing the sum of all deficits are separately tracked in the LCFS Credit Accounting system. The sum of all credits, independent of the sum of all deficits, is the amount of credits earned for the quarter. These credits would then be added to the regulated party's credit account balance. Once in the credit account the credits can be banked, transferred, or retired for compliance.

The LRT also calculates the sum of all credits and deficits on a quarterly basis. This "net" credit or deficit balance, labeled as "Total Credits/Deficits Generated (MT)," is listed on the LRT summary page for each regulated party. However, while generated credits will be transferred to a regulated party's credit account on a quarterly basis, deficits will be accumulated as an annual obligation, and the regulated party is not required to possess sufficient credits to offset its deficits until it makes its annual compliance demonstration.

Extended Credit Purchase Period

For regulated parties that may have a credit shortfall[30] in a given compliance year, staff proposes to provide an additional period in which additional credits may be purchased or otherwise acquired. Beginning 2012, a regulated party may acquire credits between January 1 and March 31, also called an "extended credit purchase period," and elect to carry back a portion or all of the purchased credits for the purpose of meeting the regulated party's compliance obligation of the year immediately prior. Credits purchased during the extended period must be generated in a previous compliance year(s) to be used to meet a previous year's compliance obligation. For example, for 2014, the additional credits purchased must have been generated between 2011 and 2013.

Continuing with the same example, a regulated party may, under certain conditions, elect to carry back all or some of the credits purchased between January 1 and March 31, 2014, and apply those credits for the 2013 compliance year. The credits are called "carry-back credits" and may only be used as part of the regulated party's compliance demonstration for the prior year. The credits carried back are considered as additional acquired credits as part of the regulated party's annual compliance demonstration.

[30] Shortfall here means that the regulated party has fewer qualifying credits in its possession than the sum of the deficits it is obligated to offset for the compliance year.

A regulated party electing to carry back credits must either:

1. Retire enough credits to meet the shortfall of the prior compliance year, or
2. If the shortfall cannot be eliminated, retire all credits eligible for carry-back.

For example, if a regulated party has a deficit balance of 200 MT CO_2e at the end of 2011 and then purchased 500 MT of additional credits eligible for carry back during the extended period in 2012, 200 MT of credits must be carried back and retired to meet the obligation in 2011. However, if a regulated party has a deficit balance of 1,000 MT at the end of 2011, then the entire 500 MT purchased credits must be carried back. Additionally, since the regulated party has a remaining balance of -500 MT in 2011, a credit-to-deficit ratio calculation will be performed to determine the extent of the shortfall.

As an interim solution, prior to the availability of the accounting system in the LRT, staff proposes to maintain the regulated party's credit balance in an external interim account and manually execute the process of accounting for carried-back credits. When the LRT enhancements are completed, both the specification of credit carry-back and account management will be handled electronically by the system. Meanwhile, staff will provide all interim solutions to regulated parties so that they may maintain account balances in parallel. For regulated parties that do not elect to carry back credits, any credits purchased in the first quarter of a year would be banked for future use.

Requirements for a Credit Transfer

A regulated party who wishes to sell or transfer credits ("the Seller") and a regulated party who wishes to purchase or acquire credits ("the Buyer") may enter into an agreement to transfer credits. The Seller may transfer credits provided the number of credits to be transferred by the Seller does not exceed the number of total credits in the Seller's credit account. When a transfer agreement is desired, it is the Seller's responsibility to provide the Buyer with a Credit Transfer Form containing the Seller's signature, date when the signature was entered, and the following information:

- Date of the proposed Credit transfer agreement.
- Names of the Seller and Buyer's Company as registered in the LCFS Reporting Tool.
- The Federal Employer Identification Numbers of the Seller and Buyer's Company as registered in the LCFS Reporting Tool.
- The first name and last name of the person who performed the transaction on behalf of the Seller's Company.
- The phone number and email of the person who performed the transaction on behalf of the Seller's Company.
- The first name and last name of the person who performed the transaction on behalf of the Buyer's Company.

- The phone number and email of the person who performed the transaction on behalf of the Buyer's Company.
- The number of credits proposed to be transferred and the credit identification numbers, if any, assigned to the credit(s) by the board.
- The price, if any, per metric ton of credit proposed for transfer, excluding any fees.

After receiving the Credit Transfer Form from the Seller, it would be the Buyer's responsibility to confirm the accuracy of the information contained in the Credit Transfer Form by signing and dating the Credit Transfer Form. The Buyer is responsible for the submission of the Credit Transfer Form with all of the required information to the EO. The EO will process the transfer request, and will update the account balance of the Seller and Buyer to reflect the proposed transfer unless the EO determines that one or more of the requirements for credit transfers has not been met. The Credit Transfer Form is provided in Appendix G.

Credits may be transferred between a Seller and Buyer on a frequency that is agreed upon between the two parties. A Seller or Buyer may elect to use a non-regulated party (a credit facilitator) to facilitate the transfer of credits for the Seller, the Buyer, or both. The credit facilitator may include, but is not limited to, a credit transfer service agency or broker who assists in arranging the transfer of credits. However, a credit facilitator cannot own or otherwise exercise control over the credits.

Retirement of Credits to Meet Obligation

At the end of a compliance year, staff proposes that a regulated party responsible for fuels that have incurred deficits must retire a sufficient number of credits to offset the deficit. If excess credits remain after meeting the obligation, those credits remain in the regulated party's credit account. If a regulated party cannot retire a sufficient number of credits to meet its compliance obligation, then all credits that are eligible to meet the compliance obligation and which are within the possession of the regulated party must be retired.

Specification of Credits to be Retired

As part of its annual compliance report, a regulated party that has met 100 percent of its compliance obligation may specify which credits are to be retired. The specification of which credits are to be retired is voluntary. If a regulated party does not make a specification, staff will use a default retirement hierarchy (see Appendix G). Under the default approach, all credits the regulated party acquired as carry-back credits (if any) during the extended period of January 1 to March 31 of the following year would be retired first. Credits the regulated party acquired during a previous compliance year would then be retired in order of purchase date (oldest first). Finally, credits the regulated party generated in previous compliance years would be retired in order of the credits were generated (oldest first).

Public Disclosure of Information and Transparency

Staff proposes to add a new subsection titled, "*Public Disclosure of Credit and Deficit Balances and Credit Transfer Information,"* to the LCFS rule. The purpose of this section is to make clear to the public and market participants that there will be routine, periodic releases of information on credit and deficit generation as well as trading activity. This subsection would permit the EO, no less frequently than quarterly, to provide public reports containing a summary of credit generation and transfer information including, but not limited to:

- Total deficits and credits generated or incurred in the most recent quarter for which data are available, including information on the types and quantities of fuels used to generate credits.
- Total deficits and credits generated or incurred in all previous quarters of the most recent year for which data are available, including information on the types and quantities of fuels used to generate credits.
- Total credits in possession of regulated parties and the total number of outstanding deficits carried over by regulated parties from a previous compliance year.
- Information on the credits transferred during the most recent quarter for which data is available including, but not limited to, the total number of credits transferred, the number transfers, the number of parties making transfers and the monthly average credit price for transfers that reported a price.
- Total credits transferred and used as carry-back credits during the first quarter of the current compliance period.

In addition, ARB staff intends to publish, at least monthly, information that would be helpful to the functioning of a credit market. Such reports may include recent information on credit transfer volumes, credit prices and price trends, and other information determined by the EO to be of value to market participants and the public. By necessity, the report would need to be limited to a level of detail that does not compromise confidential information submitted by regulated parties. Finally, the staff intends to establish a schedule for the routine release of these reports.

E. High Carbon-Intensity Crude Oil (HCICO) Provisions

<u>Background</u>

There are many production techniques for crude oil recovery. Some of the techniques require more energy or emit more GHGs to produce and pre-process the oil. Thermally enhanced oil recovery, bitumen mining, upgrading, and excessive flaring of associated gas are examples of production methods and practices that lead to increased GHG emissions. Since the LCFS regulation takes into account full lifecycle GHG emissions for fuel pathways, including all stages of feedstock production and distribution, the upstream emissions from energy-intensive crude recovery methods need to be accounted for in the regulation. The purpose of the HCICO provisions is to ensure that increases in the overall CI of CARBOB (California Reformulated Gasoline Blendstock for Oxygenate Blending) and ULSD (Ultra Low Sulfur Diesel) that might occur over time due to the use of more carbon intensive crudes are mitigated and do not diminish the emission reductions anticipated from the LCFS regulation.

The existing provisions address this issue by requiring accounting of GHG emissions associated with crude oils with high upstream emissions. The existing HCICO provisions provide a specific method for treating crude oils with high upstream emissions that were not from geographic areas substantially used in 2006.[31] A HCICO, as defined in Section 95486(b)(2)(A) of the LCFS regulation, is any crude oil which 1) was not produced in one of the countries excluded from the HCICO provision and 2) has a total production and transport carbon intensity (CI) value greater than 15 gCO2e/MJ[32].

Currently, the crude oil mix refined in CA in the year 2006 is used as the baseline to calculate average Lookup Table CI values for CARBOB and ULSD pathways. Gasoline compliance targets are calculated relative to CI for CaRFG (California Reformulated Gasoline; 90 percent CARBOB and 10 percent average ethanol); diesel compliance targets are calculated relative to CI for ULSD. Section 95486(b)(2)(A) of the LCFS regulation specifies the requirements for using the Lookup Table to determine CI values for CARBOB, gasoline, and diesel fuel used under the program. A regulated party is required to use the average CI value shown in the Lookup Table if the fuel/blendstock is derived from crude oil that is either not a HCICO, or was included in the 2006 California baseline crude mix (i.e., originated from a location which contributed two percent or more of the total crude oil refined in California in 2006 [“crude basket”]). A crude oil that does not satisfy both of these conditions is referred to as non-basket HCICO.

For fuel/blendstock made from non-basket HCICOs, the regulated party is required to use the Lookup Table CI values associated with the specific HCICO pathways and to calculate and report the associated deficits from these sources. The purpose of this requirement is to account for additional emissions generated beyond the 2006 gasoline and diesel baseline from the use of HCICOs and to encourage emission-reduction activities from these sources. If those CI values have not yet been determined and published in the Lookup Tables, the regulated party is required to propose a new pathway under Method 2B for its HCICO and obtain approval of the Executive Officer. For HCICOs, the average CI values from the Lookup Table may be used if the oil is produced using innovative methods, such as carbon capture and storage (CCS) or other methods, that reduce the CI to less than 15 gCO2e/MJ.

[31] Defined as countries or states that provided two percent or more of California’s crude supplies in 2006. The countries include: Angola, Brazil, Ecuador, Iraq, Mexico, Saudi Arabia and the States include California and Alaska.

[32] In comparison, the average crude production and transport CI included in the overall CI for the CARBOB (CI = 95.86 gCO_2e/MJ) and ULSD (CI = 94.71 gCO_2e/MJ) fuel pathways is 8.07 gCO_2e/MJ, a little more than half the value of a minimum HCICO.

All regulated parties for gasoline (diesel) calculate a “base” deficit using the difference between the average Lookup Table value for CARBOB (ULSD) and the compliance target in that year. An incremental deficit is applied only to those regulated parties that supply fuels derived from non-basket HCICOs. The incremental deficit is calculated using the difference between the Lookup Table CI values for CARBOB (ULSD) and the CI value for the specific HCICO pathway.

Summary of Crude Screening Workgroup

When the Board approved the LCFS regulation on April 23, 2009, it directed staff, through Resolution 09-31, to work with stakeholders to develop an informal screening process for assessing the CI of new or modified fuel pathways. In response to the Board’s direction, staff convened the Crude Screening Workgroup in March 2010 to address new fuel pathways for HCICOs. The intended outcome of the screening process was to identify those crudes that are clearly not HCICO, thereby reducing the number of crudes that would be subject to the more rigorous technical analyses under Method 2B.

The Crude Screening Workgroup was comprised of industry, government, environmental, and academic representatives with an objective to assist in developing a screening process for determining the CI value of crude oil sources under the LCFS. The workgroup met six times, and a smaller subgroup met weekly over a period of six weeks to discuss details of the screening process. Working with the Crude Screening Workgroup, ARB staff developed an interim process[33] for determining which non-basket crude oil sources are non-HCICO, while assigning an appropriate default carbon intensity value to those sources that are determined to be “potential-HCICO.” The intent is that the interim process will remain in place until a standardized tool/method that can be used to calculate CI values for all crude sources is developed and approved.

The interim screening process was applied, with the assistance of California Energy Commission (CEC) staff[34], to approximately 250 crude sources, of which approximately 80 percent were identified as non-HCICO. The remaining sources, which are designated as potential-HCICO, are those produced using thermal recovery methods, bitumen mining, excessive flaring, or upgrading.

Regulatory Advisory 10-04 and Supplemental Advisory 10-04A

On November 18, 2010, staff presented to the Board an update on LCFS implementation activities, including the development of a screening process for HCICOs. Through Resolution 10-49, the Board directed staff to issue guidelines

[33] Air Resources Board, February 11, 2011. Draft - Determining Carbon Intensity Values for Fuels Derived From Crude Oil. Interim Crude Oil Screening Process.

[34] Results of Initial Screening Process to Identify Potential HCICOs. Shremp, Gordon. Senior Fuels Specialist, California Energy Commission. Powerpoint Presentation at Crude Oil Screening Workgroup Meeting, February 17, 2011.

regarding the implementation of the LCFS in 2011. Staff issued two regulatory advisories that, in addition to other LCFS implementation guidance, provided clarifications related to HCICO provisions.

Regulatory Advisory 10-04, issued in December 2010, provided an extension through June 30, 2011, for the use of interim CI values for fuels derived from potential-HCICOs. The advisory stated that ARB staff will continue to work with stakeholders to develop guidelines addressing the generation and banking of credits during 2011, as potentially affected by crude oil purchases that are not part of the 2006 basket.

Supplemental Regulatory Advisory 10-04A, issued in July 2011, provided another extension through the end of 2011 for the use of interim CI values for fuels derived from potential-HCICOs. The supplemental advisory provided guidance on the treatment of credits and deficits generated from the blending of CARBOB or ULSD derived from potential-HCICOs, which was noted as a future action in Regulatory Advisory 10-04. Additionally, a list of 160 marketable crude oil names representing crude oil considered non-HCICO was provided as an attachment to the supplemental advisory to assist the regulated parties in identifying potential-HCICOs. This list of non-HCICOs to be used during the advisory period was developed using the interim screening process and is subject to change based on further ARB staff review and analysis.

Reasons for Considering Amendments to the Current HCICO Provisions

Petroleum refiners in California assert that the current HCICO provisions are overly burdensome to their industry, discriminatory toward sources of crude oil, will result in global crude-shuffling that increases GHG emissions, and would put California refiners at an economic disadvantage to out-of-state refiners. Therefore, they have requested that the 2006 baseline value be used for all production of CARBOB, and diesel fuel regardless of the type of crude supplies used by a refiner (i.e., no differentiation between the carbon intensities of crude oils). On the other hand, other stakeholders are equally as adamant that the LCFS should continue to prevent increases in lifecycle carbon emissions that could occur if higher intensity crudes are used to replace existing supplies. These parties generally support approaches that discourage or fully mitigate the refining of HCICOs in California and incentivize carbon emission mitigation techniques for oil production. ARB staff agreed to work with all interested stakeholders to explore alternatives to the current adopted approach to addressing HCICO in the LCFS. The goal of this effort was to determine if there were better options that would both meet the intent of the regulation (to ensure that the LCFS benefits are not diminished due to increases in GHG emissions from higher carbon intensity crude supplies) and address, to the extent possible, the concerns laid out by the various stakeholders.

Discussion of Proposed Modifications

Staff is proposing significant revisions to the current regulation relative to the treatment of HCICO.

Current Regulatory Requirements Related to HCICO

As stated previously, the purpose of the HCICO provisions of the LCFS regulation is to ensure that increases in the overall CI of CARBOB and ULSD that might occur over time due to the use of more carbon intensive crudes are mitigated and do not diminish the emission reductions anticipated from the LCFS regulation. The LCFS standard becomes more stringent over time, and the amount of deficits incurred per MJ of fuel supplied increase proportionately. For example, in 2011 CARBOB incurs a deficit of 0.25 gCO_2e/MJ; by 2020 the CARBOB deficits increase to 9.59 gCO_2e/MJ. Currently, the portion of the pathways attributable to the production and transport of crude oil is 8.07 gCO_2e/MJ, which comprises 8.4 percent of the CI for CARBOB and 8.5 percent of the CI for ULSD. If not mitigated, any significant increase in the CI of crude supplies used by California would reduce the anticipated benefits of the LCFS. For example, a 10 percent increase in the average CI of crude oil (from 8.07 gCO_2e/MJ to 8.88 gCO_2e/MJ) would reduce the program's effectiveness in reducing emissions from 10 percent to 9.15 percent.

Under the LCFS, regulated parties that supply CARBOB or ULSD generate deficits whenever these fuels are used in California. The amount of deficits incurred is determined by the difference between the LCFS standard in a given year and the CI of the CARBOB or ULSD. Section 95486(b)(2)(A) of the LCFS regulation specifies the procedures used to determine CI values for CARBOB and ULSD subject to the program. A regulated party is required to use the average CI value shown in the Lookup Table if the fuel/blendstock is derived from crude oil that is either not a HCICO (because it was determined to have a CI equal to or less than 15 gCO2e/MJ), or was included in the 2006 California baseline crude mix.

A crude oil that does not satisfy both of these conditions is treated as a HCICO. For fuel/blendstock made from HCICOs, the regulated party is required to apply a CI value determined for the specific HCICO pathways and to calculate and mitigate (through retirement of a similar amount of credits) the deficits incurred due to use of the HCICO. If the CI values of a HCICO have not yet been determined and published in the Lookup Tables, the regulated party is required to propose a new pathway under Method 2B for its HCICO and obtain approval of the Executive Officer.

The application of this requirement accounts for and requires mitigation of additional emissions generated beyond the 2006 gasoline and diesel baseline from the use of HCICOs. The adopted approach also encourages emission-reduction activities from sources of potential HCICO to reduce production and transport emissions to less than or equal to 15 gCO2e/MJ.

Proposed Changes to Regulatory Requirements Related to HCICO

Staff is proposing significant changes to the way increased emissions associated with HCICO fuels would be mitigated under the LCFS regulation. Most of the existing approach would be replaced with new regulatory requirements. The proposed approach would:

- Revise the portion of the CIs for CARBOB and ULSD due to the production and transport of crude oil to California refineries to reflect crude supplies used in the most recent year currently available, 2009. This would:
  - Increase the CI value attributable to the production and transport of crude oil from the current 8.07 gCO2e/MJ to a higher value of 9.72 gCO_2e/MJ;
  - Change the base CI values for CARBOB and ULSD from 95.86 gCO2e/MJ and 94.71 gCO2e/MJ to 97.51 gCO2e/MJ and 96.36 gCO2e/MJ, respectively; and
  - Require a corresponding change in the annual LCFS standards to reflect a higher CI baseline for CaRFG and ULSD. These changes would apply to fuels supplied between 2013 and 2020.

- Rescind the current approach for mitigating emissions greater than a baseline by:
  - Removing any distinctions in how crudes included in the 2006 baseline mix are treated relative to crudes from sources outside of that mix;
  - Eliminating requirements that CI increases for crudes that are classified as HCICOs be individually calculated and mitigated; and
  - Eliminating a provision that non-baseline crudes can qualify as non-HCICOs if it is demonstrated that the crude has a production and transport CI value equal to or less than 15 gCO2e/MJ.

- Establish a modified approach for mitigating higher emissions attributable to increases in crude production and transport CI by:
  - Establishing a California average crude production and transport CI based on the crude slate refined in California during 2009;
  - Performing an annual calculation, beginning in 2013, using data from calendar year 2012, of the "current" California average crude production and transport CI using the crude slate refined in California during the year. This calculation would include all crude supplied to California refineries regardless of the location of production;
  - Determining if an increase has occurred between the base year average crude CI and the annual average crude CI; and
  - Requiring that increases due to higher annual average CI be mitigated.

- Implement the mitigation requirements by:
  - Including a baseline crude average CI ($CI^{XD}_{BaselineCrudeAvg}$) and an annual crude average ($CI^{XD}_{20XXCrudeAvg}$) in the LCFS Lookup Table;
  - Requiring that if the annual crude average CI in a given year is greater than the baseline crude average CI, the incremental CI be used in the following year to calculate the additional deficits to be incurred by regulated parties that supply CARBOB and ULSD;
  - Calculating the amount of the incremental deficits for each regulated party by multiplying the incremental CI for a given year by the total amount of megajoules of CARBOB and ULSD reported by regulated parties for that year;

- o Adding the incremental deficits to the compliance obligation of regulated parties for the affected compliance period; and
  - o Requiring that each affected regulated party retire sufficient credits by the end of the compliance period to offset the added incremental deficits.

- Establish a method whereby a regulated party could earn LCFS credits if it obtains crude from sources that have implemented innovative methods such as carbon capture and sequestration to reduce emissions for crude recovery. Under this provision:
  - o The methods used to create the credits must be approved by the Executive Officer;
  - o Implementation of the innovative method must have occurred during or after the year 2010;
  - o The method must result in a reduction in carbon intensity for crude oil recovery (well-to-refinery entrance gate) of 5.00 gCO2e/MJ or greater;
  - o The number of credits will be equal to the emissions reduction achieved by the innovative method; and
  - o To avoid double counting carbon emissions, crude oil used to produce CARBOB or diesel for which a credit is allowed will be included in the Annual Crude Average carbon-intensity calculations for that year based on the carbon intensity of the crude oil prior to calculation of any innovative credits allowed.

Proposed Modifications to the Compliance Schedule and Lookup Tables

Staff is proposing revisions to Table 1 and Table 2 (the LCFS annual standards for gasoline and diesel) and Table 6 and Table 7 (the Carbon Intensity Lookup Table) of the current regulation to adjust values in those tables to align with corresponding increases in the CI of CARBOB and ULSD diesel that are proposed as part of the revised HCICO provisions of the LCFS.

i. Proposed Changes to the Average Carbon Intensity Requirements for Gasoline and Diesel

Staff is proposing to adjust the LCFS annual standards contained in the tables listing the "Average Carbon Intensity Requirements for Gasoline and Diesel" to reflect revised base year (2010) CI values for CARBOB and ULSD that occur when the base year CI for crude oil used in California refineries is changed from 2006 to 2009 (See "Proposed Changes to the Carbon Intensity Values for CARBOB and ULSD in the Lookup Tables" below). The proposed revised CI attributed to the production and transport of crude oil to California refineries results in a 1.65 gCO_2e/MJ increase in the CIs for both CARBOB and ULSD diesel, and a concurrent increase in the CI for CaRFG of 1.54 gCO_2e/MJ. This would change the base values used to determine the LCFS annual standards, which are designed to achieve specified percentage reduction in carbon intensity from the base year (2010). Staff is therefore proposing to adjust the annual standards for CARBOB and ULSD to reflect the revised CI values. This would be accomplished by applying the current percent reduction targets listed in Tables 1 and 2 to the revised values for CaRFG and ULSD diesel. This change would affect compliance periods for 2013 and beyond. No change is proposed for 2011 or 2012. The proposed revisions are shown in Tables 3 and 4 below:

Table 3. LCFS Compliance Schedule for 2011 to 2020 for Gasoline and Fuels Used as a Substitute for Gasoline.

Year	Average Carbon Intensity (gCO2E/MJ)	~~% Reduction~~
2010	Reporting Only	
2011	95.61	~~0.25%~~
2012	95.37	~~0.5%~~
2013	96.42 ~~94.89~~	~~1.0%~~
2014	95.93 ~~94.41~~	~~1.5%~~
2015	94.95 ~~93.45~~	~~2.5%~~
2016	93.98 ~~92.50~~	~~3.5%~~
2017	92.52 ~~91.06~~	~~5.0%~~
2018	91.06 ~~89.62~~	~~6.5%~~
2019	89.60 ~~88.18~~	~~8.0%~~
2020 and subsequent years	87.65 ~~86.27~~	~~10.0%~~

Table 4. LCFS Compliance Schedule for 2011 to 2020 for Diesel Fuel and Fuels Used as a Substitute for Diesel Fuel.

Year	Average Carbon Intensity (gCO2E/MJ)	~~% Reduction~~
2010	Reporting Only	
2011	94.47	~~0.25%~~
2012	94.24	~~0.5%~~
2013	95.40 ~~93.76~~	~~1.0%~~
2014	94.91 ~~93.29~~	~~1.5%~~
2015	93.95 ~~92.34~~	~~2.5%~~
2016	92.99 ~~91.40~~	~~3.5%~~
2017	91.54 ~~89.97~~	~~5.0%~~
2018	90.10 ~~88.55~~	~~6.5%~~
2019	88.65 ~~87.13~~	~~8.0%~~
2020 and subsequent years	86.72 ~~85.24~~	~~10.0%~~

These changes are needed to maintain the current stringency of the LCFS and to preserve the program's goal of reducing the carbon intensity of California' transportation fuels by 10 percent by 2020. Overall, these changes to the compliance schedules would have several impacts, such as:

- Maintaining consistency between the method used to calculate lifecycle emissions and the regulatory requirements of the LCFS;

- Providing adequate lead time for a smooth transition from the current annual standards to adjusted standards in 2013;
- Maintaining the balance and stringency in the current program relative to the rate at which carbon intensity of transportation fuels must improve and the ability of obligated parties to create sufficient LCFS credits to meet their compliance obligation; and
- Yielding a modest increase in the GHG reductions achieved under the LCFS when combined with the changes in the CIs for CARBOB and ULSD proposed in the Lookup Tables.

ii. Proposed Changes to the Carbon Intensity Values for CARBOB and ULSD in the Lookup Tables

Staff is proposing changes to Tables 6 and 7 (the Carbon Intensity Lookup Tables) of the current regulation to adjust the CI values of CARBOB and ULSD in those tables to align with corresponding increases in the CI that are proposed as part of the revised HCICO provisions of the LCFS. The CI values for CARBOB and ULSD would increase from 95.86 gCO_2e/MJ and 94.71 gCO_2e/MJ, respectively, to 97.51 gCO_2e/MJ and 96.36 gCO_2e/MJ, respectively. These revisions reflect the increase in the average CIs for CARBOB and ULSD related to the production and transport of crude oil to California refineries in the most recent year currently available (2009) and the revised calculation methodology of the proposal. The increase the CI value attributable to the production and transport of crude oil from the current 8.07 gCO_2e/MJ to 9.72 gCO_2e/MJ. As with the revisions to the annual LCFS standards, this change would affect compliance periods for 2013 and beyond.

iii. Calculation of Revised CI Values for CARBOB and ULSD

Baseline Year and Data Availability

The LCFS regulation considers 2010 as the baseline year against which a ten percent reduction in GHG emissions is mandated by 2020.[35] The compliance schedule targets for gasoline and its substitutes are based on the carbon intensity value for CaRFG, which in the year 2010 contained approximately ten percent ethanol by volume.

Because data for crude oil supplied to California refineries in 2010 was not available during development of the original regulation, Lookup Table carbon intensity values for CARBOB and diesel were based on available crude supply data for the year 2006. At the time, an assumption was made that the carbon intensity for recovery of crude oil supplied to California refineries would not change substantially between 2006 and the 2010 baseline year. This assumption turned out to be incorrect as the percentages of

[35] Air Resources Board. Proposed Regulation to Implement the Low Carbon Fuel Standard Volume I. Staff Report. Initial Statement of Reasons. March 5, 2009. at page V-7

crude recovered using thermal methods, mining, and upgrading have increased.[36,37] Therefore, as part of these proposed regulatory amendments, ARB staff is proposing updates to the baseline carbon intensity values for CARBOB and diesel using the most recently available comprehensive set of crude oil supply data from the year 2009. Furthermore, it is ARB staff's intention to revise these values again in 2012 as part of a 15-day change to these regulatory amendments. In 2012, comprehensive crude oil supply data should be available for the year 2010. ARB staff will be recalculating the "California average" annually to reflect the most current crude slate. To assist in this effort, staff is working with Professor Adam Brandt at Stanford University to develop a lifecycle assessment tool for calculating carbon intensity values for crude oil recovery.

Calculation Methodology for the Baseline Crude Average Carbon Intensity Value

We used a simple approach to calculate the Baseline Crude Average carbon intensity value (see Appendix C for details). For crude sources produced using thermally enhanced oil recovery (TEOR), bitumen mining or upgrading, a single carbon intensity value of 20 gCO2/MJ was assigned. All other crudes were assumed to be produced using conventional primary or secondary recovery methods. For these crude sources, we assumed a common "base" carbon intensity value that accounts for extraction, venting, and fugitive emissions and added to this country-specific values for flaring and transportation emissions. Crude oil produced in California, Canada, Venezuela, and Oman was recovered using a mixture of production methods. In California, approximately half of the crude was produced using TEOR.[38] The CEC data shows that 89 percent of Canadian crude was produced using TEOR, mining or upgrading; 51 percent of Venezuelan crude was produced with upgrading; and 18 percent of crude from Oman was produced using TEOR.[39,40] The resulting carbon intensity values are shown in Table 5 based on state or country of origin. The Baseline Crude Average carbon intensity, 9.72 gCO_2/MJ, was calculated by weighting these values by the percentage contribution to total crude oil supplied to California refineries.

This value is greater than the value presented in the CARBOB and ULSD pathway documents, 8.07 gCO_2/MJ, for two reasons. First, the calculation methodology is different and results in a slightly greater carbon intensity estimate. Applying the methodology described here to the 2006 crude data results in a carbon intensity for crude recovery and transport of 8.57 gCO_2/MJ. This increase is primarily the result of explicitly accounting for flaring emissions by state or country using NOAA data. Crude

[36] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.
[37] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.
[38] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.
[39] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.
[40] Schremp, G., California Energy Commission, 2011, Presentation for Crude Screening Workgroup: Results of Initial Screening Process to Identify Potential HCICOs, revised March 3, 2011.

produced in Alaska, Ecuador, Iraq, Angola, and Oman has flaring emissions that are much greater than assumed in the pathway documents. Second, the percentages of TEOR, mining, or upgrading have increased from 2006 to 2009. For example, California TEOR has increased from 14.43 percent of total California crude in 2006 to 19.48 percent in 2009. Canadian, Venezuelan, and Omani crude imports have also increased.

Table 5. 2009 Baseline Crude Average Carbon Intensity

Crude Source	Percentage of Total CA Crude	Conventional Crude CI (g/MJ)	Percentage TEOR, Mining, Upgraded	Total CI (g/MJ)
California	39.5	4.38	49.3	12.08
Alaska	15.06	7.28	0	7.28
Saudi Arabia	11.32	6.37	0	6.37
Iraq	8.49	10.39	0	10.39
Ecuador	7.81	8.29	0	8.29
Brazil	4.2	6.40	0	6.40
Columbia	2.61	5.74	0	5.74
Canada	2.31	5.75	89	18.43
Angola	2.28	7.86	0	7.86
Oman	1.58	8.87	18	10.87
Peru	0.95	5.52	0	5.52
Venezuela	0.9	6.54	51	13.41
Others	2.98	7.73	0	7.73
Weighted Average				**9.72**

Calculation Methodology for Baseline Average Carbon Intensity Values for CARBOB and Diesel

Baseline Average carbon intensity values for CARBOB and diesel (ULSD) were determined by substituting the Baseline Crude Average carbon intensity value discussed above for the crude recovery (6.93 gCO_2/MJ) and crude transport (1.14 gCO_2/MJ) values reported in the CARBOB and ULSD pathway documents.[41,42] The resulting values are 97.51 gCO_2/MJ for CARBOB and 96.36 gCO_2/MJ for ULSD.

<u>Assessment of Proposed Changes Related to HCICO</u>

Under the proposed approach, increases in crude CI would be determined and mitigated in the aggregate. The proposal would create incremental deficits only if the

[41] California Air Resources Board, February 27, 2009, Detailed CA-GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California, Version 2.1

[42] California Air Resources Board, February 28, 2009, Detailed CA-GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California, Version 2.1

average crude slate refined in California becomes more carbon-intensive. This aggregate approach differs from the current approach, which mitigates only those increases in crude CI that can be attributed to crudes classified as HCICOs. A second major difference is that the proposed approach allows for "the industry as a whole" to shift its crude slate and not incur additional deficits as long as the average CI of the California crude slate does not increase relative to the baseline year. Finally, the proposed approach necessitates more timely and complete reporting of all of the crude used in California refineries, but eliminates the need for regulated parties to determine the CIs for every crude classified as HCICO.

Staff believes the proposed changes are overall a significant improvement to the current approach and are clearly superior in a number of aspects:

- First, the proposal ensures that all sources of crude supplies are accounted for in a consistent manner in a Statewide average, and assures the mitigation of GHG emissions that result from an increased CI from crude production and transport.
- Second, the current regulation would allow unmitigated CI increases in crude oil supplies from countries in the baseline, and from crudes that have relatively high CIs but are able to demonstrate they do not exceed 15 gCO2e/MJ threshold for HCICO. The proposed approach removes the possibility that such crudes could cause the average CI from production and transport to increase but not be mitigated.
- Third, the proposed approach provides additional flexibility for refiners to:
  - o Change crude slates without incurring deficits (assuming the state average carbon intensity does not increase over the baseline average).
  - o Avoid the need to prepare and submit to the Executive Officer Method 2B applications, seeking approval of CIs for crudes classified as a potential-HCICO.
- Fourth, the proposal more accurately calculates the 2010 CI baseline for California gasoline and diesel upon which the LCFS is based. Because the revised CI baseline is slightly higher, the ten percent reduction goal of the LCFS will produce greater net GHG emissions reductions under the proposal. For example, the potential incremental GHG benefits under the revised compliance schedules are estimated to be about 259,000 MT CO_2e in 2020; therefore, the total GHG emissions reductions for the LCFS in 2020 are estimated to be about 16.1 MMT CO_2e instead of the original 15.8 MMT CO_2e.

Consideration of Alternatives to the Proposed Changes Related to HCICO

As described above, ARB staff believes that the proposed changes to the HCICO provisions of the LCFS regulation are a significant improvement over the current approach. The proposal provides greater certainty that an increase in the CI of crude will be mitigated, provides greater flexibility to refiners to manage crude slates, is easier to administer once a comprehensive system to assign CIs to crudes is implemented[43], and creates slightly greater GHG reductions from the LCFS program. However, staff is continuing to explore options that could improve the proposal, and may recommend changes by the time the Board considers this matter. Therefore, staff invites comments and suggestions on how the proposal could be improved. Specifically staff solicits suggestions on:

- Alternative methods to allocate incremental deficits so that mitigation responsibility is allocated to those regulated parties most responsible for an increase in the average crude CI.
- Alternative and additional methods of providing incentives for innovation that significantly reduces the CI of non-conventional crudes and crudes that require high-energy production.

Staff is also considering how to address HCICO refined in 2011 and 2012 (e.g., the generation of deficits and potential impacts on credit balances) as well as how to handle the processing of imported intermediate feedstocks, such as cat cracker feed.

F. Electricity Regulated Party Revisions

Overview

In the LCFS regulation, regulated parties for electricity used as a transportation fuel include electric utilities, non-utilities installing electric vehicle service equipment (EVSE) with a customer contract, business owners, and homeowners. The Board directed staff in Resolution 09-31 to review the provisions applicable to regulated parties for electricity and propose amendments if appropriate. Since the Board approved the regulation, the markets for electric vehicles (EV) and EV-fueling infrastructure have evolved and continue to evolve. As a result, staff is proposing modifications to the designation of regulated parties for electricity.

In the regulation, regulated parties for electricity are eligible to receive LCFS credits for delivering electricity for transportation use in California. By providing a lower-carbon fuel relative to gasoline, parties can earn an LCFS credit for each metric ton of CO_2 equivalent ($MTCO_2e$) emissions avoided through the use of electricity—a transportation fuel with much lower carbon intensity (CI) than the 2020 standard specified in the LCFS regulation. The credits will have a monetary value when sold to regulated parties who must offset deficits created by their supply of fuels with CIs that exceed the LCFS standards.

Staff has proposed regulatory amendments to: (1) eliminate ambiguity in some cases of regulated party designation; (2) clearly award potential credits for residential and

[43] A lifecycle assessment tool for calculating carbon intensity values for crude oil recovery is being developed by Professor Adam Brandt at Stanford University under contract with ARB and will be completed in 2012.

public-access vehicle charging; (3) incorporate vehicle charging applications that were not foreseen when the regulation was adopted; and (4) maximize the number of credits available for use in the LCFS program. In the revised language, staff seeks to ensure fair treatment of regulated parties and to incent electric transportation. The proposed changes discussed here are limited to on-road electric refueling.

Regulated parties for electricity are currently opting into the regulation to receive LCFS credits and have submitted reports for fuel transactions for the first two quarters of 2011. The proposed amendments are necessary to align the regulation with current EV charging applications and to reflect staff's intent to award credits in a fair manner.

<u>Current Regulation Hierarchy for Credit Recipients</u>

As allowed in the current regulation, electric utilities can potentially receive credits for electricity delivered through residential charging equipment and for public EVSE they have installed. However, non-utility Electric Vehicle Service Providers (EVSPs) are also installing charging equipment in homes, for public access, and on private business property for employee use. In cases where a non-utility EVSP has installed equipment, the regulation designates the non-utility EVSP as the potential credit recipient rather than the utility. While staff intended non-utility EVSPs to receive credits only for fuel delivered through public charging equipment, the regulation can be interpreted to include residential charging credits to non-utility EVSPs. The regulation allows for two additional potential credit recipients: businesses that provide access to EVSE on their property and homeowners. Business owners and homeowners are eligible to receive LCFS credits only if they have a contract to do so with the appropriate utility.

<u>Proposed Regulation Modifications</u>

Staff is proposing to clarify the regulation to designate electric utilities as the regulated parties for EV charging in single- and multi-family residences. Staff is further proposing to add several requirements that must be met before utilities can receive credit for residential charging. Utilities must:

1. Use all credit proceeds as direct benefits for current EV customers.
2. Provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid.
3. Educate the public on the benefits of EV transportation through outreach efforts.
4. Include in annual reporting a summary of efforts to meet requirements 1, 2, and 3, as well as an accounting of the number of EVs known to be operating in the service territory.

Staff is also proposing to designate non-utility EVSPs and electric utilities as the regulated parties for transportation fuel supplied through public charging equipment that they have installed. For the LCFS regulation, a non-utility EVSP is defined as the entity that installs the EV-charging equipment, or has had an agent install the equipment, and who has a contract with the property owner or lessee where the equipment is located to maintain or otherwise service the charging equipment. The contract must be valid during the corresponding reporting period. For a utility to qualify as the regulated party for public access charging, the utility would also need to have a similar contract valid during the reporting period.

In an effort to maximize the number of credits captured by regulated parties, staff is proposing to add the local utility as the default regulated party if the EVSP elects not to participate in the regulation. Under the proposal, with EO approval, the utility can become eligible to be the regulated party for the electricity supplied by the public access charging equipment.

Staff is also proposing to add requirements that the regulated parties for public access charging must meet to receive credits. The requirements are similar to those specified for utilities for residential charging.

Staff is proposing to add an opportunity for EV fleet operators to become regulated parties. Under the proposal, a company operating a fleet of three or more EVs may opt into the regulation to become a regulated party, while the utility is eligible to be the regulated party for fuel supplied to fleets of less than three EVs. If the fleet operator chooses not to become a regulated party, the electric utility operating in the service territory where the fleet vehicles are charged can become eligible to be the regulated party with EO approval. To receive credit for fuel supplied to an EV fleet, regulated parties must annually report an accounting of the number of EVs in the fleet.

Staff is also proposing to allow employers who offer on-site EV charging equipment to their employees to become regulated parties. Under the proposal, if the employer chooses not to become a regulated party, the electric utility operating in the service territory where the fleet vehicles are charged can become eligible to be the regulated party with EO approval. Staff is further proposing to require regulated parties for employee EV charging to:

1. Educate employees on the benefits of EV transportation.
2. Annually report on the efforts of (1), as well as an accounting of the number of EVs known to be charging at the business.

<u>Current and Expected Near-Term Market for Electric Vehicle Charging</u>

Electric utilities supply the fuel for charging electric transportation. Utilities are also installing separate meters for those residential EV customers who choose an EV time-of-use (TOU) rate structure that encourages EV charging during off-peak hours (generally overnight). In addition, some utilities plan to install EVSE for public access EV charging.

Non-utility EVSPs are installing many EVSEs in single-family homes and also plan to install them in multi-family homes. In addition, non-utility EVSPs are currently installing public access EVSE and establishing contracts with business owners where the equipment is located and contracts with EV owners to access the equipment. The property owner may buy or lease the EVSE.

<u>Justification of Proposal</u>

In preparing the proposal to modify the electricity regulated party language, staff established three goals. First, staff kept the proposed language simple to avoid confusion in regulated party designation and maintain relevancy as the EV charging market continues to evolve. Second, staff limited the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties who need to purchase credits. And finally, staff included default regulated parties in the proposed language to maximize the number of credits captured and available for purchase and use for compliance.

Staff is proposing to designate electric utilities as the regulated parties for EV charging in single- and multi-family residences as well as for public access charging equipment they install with a contract. Utilities have been actively preparing for California's EV market. Many utilities have been preparing to accommodate the expected growth in EV population by increasing customer education and outreach, developing EV electricity rate schedules, and evaluating system impacts. As EV customers evaluate their home charging options, some require panel upgrades and the installation of second meters to receive EV TOU rates. In some cases, utilities have replaced transformers as a result of EV charging. Further upgrades to the electric distribution system are anticipated in some areas as the number of EVs operating in California increases. For example, the San Diego Gas & Electric Company has estimated costs to accommodate residential and commercial EV services will range from $1 to $1.5 million annually for 2010 to 2012.[44]

To recover these costs, the CPUC has ruled, in their decision on Phase 2 of the Alternative Fueled Vehicle Proceeding,[45] that until June 30, 2013, "all residential service facility upgrade costs in excess of the residential allowance shall be treated as common facility costs rather than being paid for by the individual plug-in hybrid and electric vehicle customer." Staff is proposing to designate electric utilities as the regulated parties for residential charging to make them eligible to receive LCFS credit revenue that may offset utility costs that are a direct result of the EV market. Staff is further proposing that credit revenue must be returned to EV customers through direct benefits.

Staff is further proposing to designate non-utility EVSPs as the regulated parties for public EV charging that they install. The credit revenue that they will be eligible for will reward them for establishing the public charging network that is required to support a successful EV market.

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[44] California Air Resources Board, Utility Survey of SDG & E

[45] California Public Utilities Commission Phase 2 Decision Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code Section 740.2

Stakeholder Outreach

When the Board approved the LCFS regulation in April 2009, they directed staff in Resolution 09-31 to continue working with stakeholders on the electricity regulated party language and to propose language changes if necessary. Staff established an Electricity Workgroup with stakeholders and has held three meetings since the regulation was approved. Participants included representatives from utilities, non-utility EVSPs, oil refineries, the CPUC, the California Energy Commission, and environmental groups. Workgroup members have submitted written comments in addition to participating in the Workgroup meetings.

Value of LCFS Credits

Staff estimates that in 2011, there will be 5,000 to 11,000 electric vehicles operating in California. This includes full-electric vehicles like the Nissan Leaf and Tesla Roadster, and plug-in hybrids like the Chevy Volt. Based on typical annual miles traveled and using electricity supplied from the California grid, a full battery electric vehicle (BEV) could earn on the order of two credits in 2011, while a plug-in hybrid could earn about 1.5 credits in 2011 (one credit is equal to one $MTCO_2e$). The projected total number of credits available in 2011 for the electricity-fueled miles traveled by these vehicles is 8,000 to 22,000. The potential value of the credits for all electric vehicles statewide in 2011, based on a range of $15 to $50 per credit, could range from $114,000 to $1,100,000.

In 2020, when the LCFS CI standard is lower, the potential credits that an electric vehicle could earn are less than 2011 credits, assuming that the EV technology does not significantly improve. Staff predicts that BEVs could earn approximately 1.7 credits per vehicle, while plug-in hybrids could earn 1.3 credits per vehicle. The number of credits projected for the year 2020 varies considerably based on the projected number of electric vehicles. LCFS scenarios are based on 490,000 to 1,780,000 electric vehicles (both battery and plug-in hybrid) in 2020. Based on these scenarios, LCFS credits available in 2020 could be 700,000 to 2,500,000. Compared to the total reduction of CO_2e in 2020 (24 $MMTCO_2e$), credits could be 3 to 10 percent of the total reduction. The potential value of the credits based on a range of $15 to $50 per credit, could range from $10 to $124 million.

G. Energy Economy Ratio (EER) Revisions

Energy Economy Ratios

Staff is proposing three changes to the Energy Economy Ratios (EER). Staff is proposing these changes to reflect the use of engine efficiency and fuel efficiency data that was not available during the original rulemaking in April 2009. The first change is the addition of a new EER of 1.0 for CNG/LNG heavy-duty compression-ignition engines. The EER of 0.9 that is currently in the rule for all CNG/LNG heavy-duty engines would be applicable only to heavy-duty spark-ignition engines. The second proposed change is to change the EER for light duty BEVs and plug-in-hybrid electric vehicles (PHEV) from 3.0 to 3.4. The third proposed change is to change the EER for light-duty fuel cell vehicles (FCVs) from 2.3 to 2.5. The basis for both of the changes being proposed by the staff is the availability of new data on the energy efficiency of heavy-duty engines burning CNG and LPG, BEVs, PHEVs, and FCVs. Furthermore, staff proposes to delete the 1.3 divisor for EVs and FCVs that was originally intended to account for cleaner conventional vehicles in 2016 and beyond. In lieu of the divisor, staff is proposing that the EERs be revisited periodically to account for improvements in all engine and vehicle technologies.

Heavy-Duty CNG/LPG Vehicles

Recent ARB certification data show that the energy efficiency of heavy-duty compression-ignited engines burning CNG and LPG is the same as that of heavy-duty diesel fueled engines of comparable size and horsepower. It is for this reason that the staff is proposing an EER of 1.0 for compression-ignition heavy-duty engines burning CNG and LPG.

Light Duty

Since the publication of the ARB's Initial Statement of Reasons for the Low Carbon Fuel Standard regulation in March 2009, fuel efficiency data has become available for two electric vehicles that are expected to constitute the majority of electric car sales in the next several years. These vehicles are the Chevy Volt and the Nissan Leaf. The fuel economies for these vehicles have been published in the federal Government's Fuel Efficiency Guide. The fuel efficiency for the Chevy Volt, operating in the electric-only mode, was measured at 93 miles per gallon gasoline equivalent, while the fuel efficiency for the Nissan Leaf was measured at 99 miles per gallon gasoline equivalent. For the Chevy Volt, the reference vehicle is the Chevy Cruze. The fuel efficiency for the Chevy Cruze is 28.3 miles per gallon. The corresponding EER for the Chevy Volt (the quotient of its fuel efficiency and that of its reference vehicle) is 3.29. For the Nissan Leaf, the reference vehicle is the Nissan Versa, which has a fuel efficiency of 28.4 miles per gallon. The corresponding EER for the Nissan Leaf is 3.49. The average EER for the Volt and Leaf is 3.39, or 3.4. This EER value would be used in the calculation of all credits originating from the use of electricity in light-duty cars.

Light-Duty Fuel Cell Vehicles

The EER for light-duty fuel cell vehicles is based on the published fuel economies for the 2011 Honda FCX Clarity and the 2011 Mercedes-Benz F-Cell. The published fuel economies for the Clarity and the F-Cell are 60 miles per kilogram of hydrogen, and 53 miles per kilogram, respectively. These translate to about 61 miles per gallon of gasoline equivalent, and about 54 miles per gallon of gasoline equivalent, respectively. The reference vehicle for FCX Clarity is the Honda Accord, while for the F-Cell they are the Mercedes SLK350, SLK300, and C300. The fuel efficiency for the Accord is about 26 miles per gallon, while for the SLK350, SLK300, and C300 the fuel economies are about 21 miles per gallon. The corresponding EER for the Clarity is 2.35, while for the F-Cell it is 2.57. Averaging the EERs of the Clarity and the F-Cell gives an average EER of 2.46, or 2.5, which is proposed to be the EER for purposes of calculating credits.

H. Revisions to Reporting and Recordkeeping Provisions

Designating the LRT for LCFS Quarterly and Annual Reporting

There is no clearly designated single process mandated in the existing LCFS regulation to be used for reporting. The current regulation only specifies that "a regulated party must submit an annual compliance and quarterly progress report by using an interactive, secured internet web-based form." To facilitate such reporting, ARB staff developed the online LCFS Reporting Tool (LRT), which has been operational since early 2010 and in production since December 2010. It is readily accessible at www.arb.ca.gov/lcfsrt for electronic reporting by all regulated parties.

A total of 70 regulated parties have used the LRT for reporting during 2010 and for first quarter 2011 reporting, both for manual entry of fuel transaction data via the user interface and through XML data file upload submission. This has been the only means used for LCFS reporting by all regulated parties; the LRT, therefore, has become the *de facto* standard for electronic submittal of required LCFS reports. Thus, the staff's proposal to mandate the use of the LRT simply codifies the existing standard practice of regulated parties.

As with most industries, the transportation-fuels sector values certainty, and specifying that only the LRT, which is accessible from ARB's website, can be used for reporting ensures such certainty. For similar reasons, the requirement to use the LRT ensures standardization and consistency, which would help facilitate credit trading between regulated parties (especially when the LRT version 2.0 is developed, which will automate credit trades and credit reporting). In addition, because all regulated parties are using the LRT and ARB makes it available for free, there are no additional costs involved with using the LRT for regulated parties. By contrast, the purchase of and training with different, commercially-developed reporting software would almost certainly involve additional costs for regulated parties. For the above reasons, staff proposes to mandate use of the LRT as the only online reporting mechanism for use by regulated parties.

Rounding to Nearest Whole Number, Reporting of Volumes Expressed in GGE

Staff proposes to amend section 95484(c)(5)(C) of the existing regulation, which is now section 95484(b)(5)(C) in the proposed regulation, by eliminating the reporting of fuel volume in terms of "gasoline gallon equivalent (gge)." The use of gge was part of an earlier version of the LCFS regulation in which conversion of fuel volumes to gge values was required as part of fuel transaction reporting. This is no longer needed because the LRT now accepts volume inputs in their native units (i.e., "gallons" for gasoline, diesel and liquid biofuels; “scf” for CNG, LNG and Biogas; “kWh” for electricity; and “kg” for hydrogen). To improve reporting and for consistency in how regulated parties are recording their transactions, staff is also proposing to change the provisions in section 95484(b)(5)(C) for reporting significant figures to simply require reporting to the nearest whole unit.

Renewable Identification Number Reporting

Staff proposes to delete section 95484(b)(3)(A)4. of the existing regulation to no longer require the reporting of “all Renewable Identification Numbers (RINs) that are retired for facilities in California.” Staff determined that this provision was of limited utility and no longer needed. Further, staff proposes to remove the reference to quarterly reporting of RINs in Table 3.

Product Transfer Document

The current regulation uses the term “Product Transfer Document” (PTD) but does not define it; rather, the regulation specifies information that must be contained in the PTD. It is staff’s understanding that PTDs, instead of being a single document, can be a collection of related documents. Thus, staff described a PTD in the LCFS Guidance Document, version 1.0,[46] as a document or documents that may include, but is not limited to, one or more of the following: contract, invoice, bill of lading, RFS2 product transfer document, meter ticket, and rail inventory sheet. The guidance document further describes a PTD as a document or combination of documents that is commonly used and accepted in the industry for the subject fuel. Moreover, if multiple documents are used for an authentication, each document must contain information that identifies their association to each other. To clarify the regulation, some stakeholders have suggested codifying the guidance document’s language into a formal definition for a PTD. Staff agrees and has proposed a definition for PTD accordingly.

Reporting Requirements for Gasoline and Diesel Fuel

Annual Reports

The proposed change is to add to the annual reporting requirements, starting 2012 and for each year thereafter, information on the crude oil supplied to California refineries in a calendar year. These data will be used to estimate the annual average crude oil carbon-intensity. These reporting requirements will be applicable to the producers of CARBOB, gasoline, and diesel. Specifically, the following data for each refinery will be required under this provision:

1. Volume (in gallons) and marketable crude oil name (MCON) of all crude oil supplied to the refinery that was produced in California using thermal enhanced oil recovery (TEOR) methods.

[46] See http://www.arb.ca.gov/fuels/lcfs/LCFS_Guidance_%28Final_v.1.0%29.pdf, accessed Oct. 9, 2011.

2. Volume (in gallons) and MCON of all crude oil supplied to the refinery in the current compliance period that was produced in California using non-TEOR methods.
3. Volume (in gallons), MCON, and Country (or State) of origin for all crude oil supplied to the refinery in the current compliance period that was imported.

Quarterly Reports

Staff proposes to add, to the quarterly reporting requirements, all imports of petroleum blendstocks, finished fuels, and petroleum intermediates that can be further processed to produce blendstocks or finished fuel. The volumes of such imported products would need to be reported on an individual basis.

I. Miscellaneous

Modifications to the Definitions of "CNG," "LNG," and "Biogas"

The existing regulation defines "compressed natural gas (CNG)," "liquefied natural gas (LNG)," and "biogas (biomethane)," in part, by reference to the existing California motor vehicle fuel specifications for CNG. These fuel specifications are codified at title 13, California Code of Regulations, section 2292.5. Under the original LCFS rulemaking, staff included this reference to the fuel specifications to ensure that only natural gas that was sold, supplied or offered for sale in California for transportation purposes would be credited under the LCFS program. However, staff has determined that the reference to title 13 is unnecessary given that the regulation already explicitly applies only to fuels sold, supplied, or offered for sale for transportation purposes. Further, the title 13 specifications are based on criteria pollutant standards, while the LCFS is based on carbon intensity requirements, so the linkage between the two is superfluous (i.e., the two regulations exist independently). Finally, ARB staff is currently collaborating with local air district staff to update the motor vehicle fuel specifications; thus, staff believes the criteria pollutant aspects of the motor vehicle fuel specifications are more appropriately addressed through the title 13 specifications rather than being linked directly to the LCFS. Based on the above considerations, staff is proposing to eliminate the reference to the motor vehicle fuel specifications from the above definitions.

Codification of LCFS Advisory Provisions

To provide clarity during the early implementation of the LCFS, ARB staff issued a number of advisories.[47] Staff believes a number of these advisories set forth guidance that should be codified in the regulation. For example, it was suggested that the regulation, like the advisories, specify default CI values to be used by regulated parties when faced with purchasing fuel with an unknown CI and fuel pathway. The proposal addresses this scenario and proposes to codify other provisions discussed in the advisories.

[47] See http://www.arb.ca.gov/fuels/lcfs/070111lcfs-rep-adv.pdf, http://www.arb.ca.gov/fuels/lcfs/122310lcfs-rep-adv.pdf, http://www.arb.ca.gov/fuels/lcfs/093010lcfs-rep-adv.pdf, and http://www.arb.ca.gov/fuels/lcfs/070910lcfs-rep-adv.pdf.

V. ENVIRONMENTAL IMPACT ANALYSIS

A. Introduction

This chapter provides an environmental analysis of the proposed regulatory action. Based on ARB's review of the proposed amendments, staff has concluded that the proposed amendments to the Low Carbon Fuel Standard (LCFS) regulation would not have a significant or potentially significant adverse effect on the environment. The analysis in this chapter explains the potential effects that staff examined and the basis for reaching its conclusion.

B. Background on Environmental Review Analysis

ARB is the lead agency for the proposed regulation and has prepared this environmental analysis pursuant to its certified regulatory program. The California Environmental Quality Act (CEQA) at Public Resources Code section 21080.5 allows public agencies with regulatory programs to prepare a plan or other written document in lieu of an environmental impact report or negative declaration once the Secretary of the Resources Agency has certified the regulatory program. ARB's regulatory program has been certified by the Secretary of the Resources Agency.[48] As required by ARB's certified regulatory program, and the policy and substantive requirements of the CEQA, ARB has prepared this environmental analysis to assess the potential for significant long or short term adverse environmental impacts associated with the proposed action and a succinct analysis of those impacts.[49] In accordance with ARB's regulations, the assessment also describes any beneficial impacts.[50] The resource areas from the state CEQA Guidelines environmental checklist were used as a framework for assessing potentially significant impacts.[51] In accordance with ARB's certified regulatory program, for proposed regulations the environmental analysis is included in the Staff Report: Initial Statement of Reasons (ISOR) for the rulemaking. [52]

CEQA requires that when ARB adopts a rule or regulation requiring the installation of pollution control equipment, or a performance standard or treatment requirement, that ARB conduct "an environmental analysis of the reasonably foreseeable methods by which compliance with that rule or regulation will be achieved."[53] The analysis shall include reasonably foreseeable environmental impacts of the methods of compliance, reasonably foreseeable feasible mitigation measures related to significant impacts, and reasonably foreseeable alternative means of compliance that would avoid or eliminate significant impacts. The analysis should not engage in speculation, nor is the detail of a project-level analysis required.

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[48] State CEQA Guidelines Cal. Code Regs., tit. 14,§ 15251 (d); Cal. Code Regs., tit. 17,§, sections 60005-60008.)
[49] Cal. Code Regs., tit. 17,§ 60005, subd. (b).
[50] Cal. Code Regs., tit. 17,§ 60005, subd. (d).
[51] State CEQA Guidelines, Appendix G.
[52] Cal. Code Regs., tit. 17,§ 60005.
[53] PRC section 21159; Cal. Code Regs., tit. 14,§ 15187

CEQA discourages speculation; however, drafting an environmental document necessarily involves some degree of forecasting.[54] While foreseeing the unforeseeable is not possible, an agency must use its best efforts to find out and disclose all that it reasonably can. If after thorough investigation, a lead agency finds that a particular impact is too speculative for evaluation, the agency should note its conclusion and terminate discussion of the impact.

If comments that are received during the public review period raise significant environmental issues, staff will summarize and respond to the comments in writing. The written responses will be included in the Final Statement of Reasons (FSOR) for the proposed regulation amendments. In accordance with ARB's certified regulatory program, prior to taking final action on the proposed regulation amendments, the decision maker will approve the written responses.[55] If the regulation is adopted, a Notice of Decision will be posted on ARB's website and filed with the Secretary of the Natural Resources Agency for public inspection.[56]

C. Summary of 2009 Environmental Analysis

The environmental analysis published in the 2009 LCFS ISOR[57] focused on the significant GHG emission reductions that the regulation would achieve through the production and use of lower-CI transportation fuels. The analysis also included the potential GHG emission reductions realized through changes in the vehicle fleet composition that would be available to use these lower-CI transportation fuels. Staff estimated that a reduction of about 16 million metric tons of CO_2-equivalent ($MMTCO_2e$) would come solely from the combustion of transportation fuels in California in 2020. If the full-fuel-lifecycle is included in the GHG benefits of the LCFS—taking into account GHG reductions outside of California—there would be an estimated reduction of about 23 $MMTCO_2e$.

As part of the analysis, staff estimated the number of potential new transportation fuel facilities that could be built in California. This estimate relied on the volume of biomass available in the State, projects that were undergoing the permitting process at the time of the analysis, and the projected demands of both the LCFS and RFS2 in 2009. Staff estimated that potentially six ethanol facilities, 18 cellulosic ethanol facilities, and six biodiesel facilities could be operational in the State by 2020. In the 2009 analysis, staff assumed that petroleum refining throughput in California would not be affected by the LCFS; California may become a net exporter of transportation fuels rather than the net importer that it currently is when California consumption of petroleum-based fuels declines. As a result, staff did not anticipate any changes in the emissions from petroleum refineries, power plants, or existing corn ethanol facilities over the baseline

[54] Cal. Code Regs., tit. 14,§ 15145; Cal. Code Regs., tit. 14,§ 15144.
[55] Cal. Code Regs., tit. 17,§ 60007, subd (a).
[56] Cal. Code Regs., tit. 17,§ 60007, subd. (b).
[57] Air Resources Board. Proposed Regulation to Implement the Low Carbon Fuel Standard Volume I. Staff Report. Initial Statement of Reasons. March 5, 2009.

projections. In addition, staff assumed that any environmental impacts of additional electricity demand would be offset by the requirements of the 33 percent renewable portfolio standard, and off-peak charging would avert the need for additional power plants. Lastly, at the time of writing the staff report, the California corn ethanol facilities were among the cleanest in the nation, and staff did not anticipate the need to upgrade their facilities within the 2020 time frame. Therefore, any impacts above the baseline were attributed solely to potential new biorefinery facilities operating in the State.

In addition to the GHG benefits, staff also expected the LCFS to result in no additional adverse impacts to California's air quality due to criteria and toxic air pollutants. When calculating the emissions from potential new facilities, staff assumed use of the cleanest conversion and air pollution control technologies. This assumption was based on stringent New Source Review regulations affecting the permitting of these facilities. Staff recommended that any emissions from these facilities, if permitted, would be mitigated and offset, consistent with local air district and CEQA requirements. Staff identified the truck trips associated with the delivery of feedstock and finished fuel as the larger source of criteria pollutant emissions. Staff proposed that these emissions could be mitigated by using newer trucks for the trips, as prescribed by other state and federal regulations (such as LEV and CAFE standards). Furthermore, the emissions could be offset on a statewide basis through the use of these cleaner transportation fuels in California vehicles. Nevertheless, staff recognized that there was still a potential for localized impacts, which prompted a further evaluation as described below.

Staff performed a health risk assessment to estimate the potential cancer risk from a biorefinery. To establish a plausible upper-bound, staff evaluated a scenario consisting of three co-located facilities. Details of this analysis can be found in Chapter VII of the 2009 ISOR. The highest potential cancer risk associated with on-site emission risk was estimated to be 0.4-out-of-a-million at the fence line of the facility. When including both on-site and off-site emissions in the risk analysis, cancer risk was estimated to be 5-out–of-a-million. In addition to the potential cancer risk, staff also analyzed the impacts related to $PM_{2.5}$. This analysis estimated an additional 20 premature deaths, seven hospital admissions, and 314 cases of asthma, acute bronchitis, or lower respiratory symptoms.

Staff further analyzed the ambient ozone impacts and determined that the air quality model could not reliably predict the impact because the concentrations of smog-forming pollutants associated with the LCFS were not statistically significant above the baseline. Lastly, in the 2009 environmental analysis, staff provided qualitative, and in a few cases quantitative, evaluations of impacts on other types of media. Staff included impacts on water use and water quality, agricultural resources, biological resources, geography and soils, hazardous materials, mineral resources and solid waste. Finally, staff provided a brief discussion on the commitment to develop a plan to address sustainability components related to the production of feedstock and transportation fuels.

D. Analysis of Proposed Regulation Modifications

For the proposed amendments, staff analyzed potential environmental impacts in terms of reasonably foreseeable methods of compliance. This section briefly explains each modification provision and the reasonably foreseeable methods by which compliance with the provisions will be achieved.

The proposed provisions include several amendments that are administrative in nature. These include provisions to opt-in and opt-out of the regulation, a provision which mandates use of the LCFS Reporting Tool, and a provision to convert the Method 2A/2B application process to a certification process.

In addition to the administrative provisions, staff is proposing regulation amendments which are more extensive than administrative changes. These include amendments to enhance the regulated party provision by expanding the definition of "producer", specify a credit tracking and trading process, revise the Energy Economy Ratios (EER) for electricity and fuel cell vehicles, add a regulatory approach for High Carbon Intensity Crude Oil (HCICO), and modify the designation of regulated parties for electricity.

Opt-In and Opt-Out Provisions

Staff determined that there are no significant adverse environmental impacts due to this proposal. Staff is proposing to modify language in the regulation to clarify procedures for parties to opt-in and to opt-out of the regulation. The modifications would encourage parties to register for the regulation by providing simple and clear steps to become a regulated party (opt-in) and to cease being a regulated party (opt-out). Compliance with this provision is administrative in nature.

Staff anticipates that the modifications to the opt-in and opt-out provisions could result in a greater number of parties who are eligible to generate credits registering for the regulation. As a result, a greater number of credits could potentially be generated and available on the credit market for purchase by regulated parties seeking to meet compliance obligations. In turn, more credits available for purchase for compliance purposes could potentially deflate credit value and lower overall compliance costs.

Enhanced Regulated Party Provisions

Staff determined that there are no significant adverse environmental impacts due to this proposal. Staff is proposing to expand the definition in the regulation of "producer" to include production facilities located outside California. This modification would allow out-of-state producers to opt into the regulation. Staff is also proposing to expand the definition in the regulation of "import facility" to include the transportation equipment that held or carried the product at the point the equipment entered California. These modifications would allow out-of-state fuel producers and intermediate entities having title of an imported fuel to opt into the regulation, become regulated parties, and therefore generate and hold LCFS credits.

Mandatory LCFS Reporting Tool Use

Staff determined that there are no significant adverse environmental impacts due to this proposal. Currently the LCFS regulation mandates the use of "an interactive, secured internet web-based form" for submitting annual compliance and quarterly progress reports. Since all reporting parties are using ARB's LCFS Reporting Tool (LRT) as that "interactive, secured internet web-based form," staff is proposing to modify the regulation to require the LRT be used for all reporting requirements. Compliance with this provision is administrative in nature.

Credit Trading

Staff determined that there are no significant adverse environmental impacts due to this proposal. Staff is proposing to add provisions in the regulation that clarify how credits and deficits are tracked, and to specify the process to be used to acquire, bank, transfer, and retire credits. In the proposal, staff is also including a provision that allows a regulated party to acquire credits in the first quarter of a year to meet a compliance obligation in the previous year, as long as those credits were generated in a previous year. This proposal further seeks to establish requirements relating to the public release of information concerning the generation of deficits and the generation, use, and transfer of credits.

Revised EERs

Staff determined that there are no significant adverse environmental impacts due to this proposal. Staff is proposing three modifications to the Energy Economy Ratios (EERs). First, staff is proposing to add to the regulation an EER of 1.0 for heavy-duty compression-ignited engines fueled with compressed natural gas (CNG) or LPG. Currently, the EER in the regulation for these vehicles is 0.9. Second, staff is proposing to change the EER for the electricity used in light-duty battery electric vehicles and plug-in hybrids from 3.0 to 3.4. Third, staff is proposing to change the EER for light-duty fuel cell vehicles from 2.3 to 2.5.

The proposed changes to EER values have the potential to increase the number of credits generated for CNG/LNG, electricity, and hydrogen transportation fuels. An increase in the number of credits available for regulated parties to purchase could decrease the value of a credit, potentially decreasing compliance costs.

Certification Process for Method 2A/2B

Staff determined that there are no significant adverse environmental impacts due to this proposal. In the current regulation, the process through which a regulated party receives approval to use a carbon intensity value determined through the Method 2A/2B process requires an Executive Officer or Board hearing. Staff is proposing to convert this regulatory process to a certification process to save staff resources, yet maintain the technical rigor and public input of the current requirements. Compliance with this provision is administrative in nature.

High Carbon Intensity Crude Oil (HCICO)

As part of the regulatory amendments for the handling of crude oil, three substantial changes have been proposed. First, the concept of a grandfathered “basket” of crudes would be replaced with a “baseline,” which accounts for the emissions intensity of all crude sources refined in California. Second, the baseline carbon intensity values for CARBOB and ULSD and the associated base deficit attributed to producing these fuels would be referenced to a more recent baseline year to reflect more accurate data than were available for the 2009 rulemaking. Third, the incremental deficit would not apply a 15.00 gCO_2e/MJ bright line for differentiating between high-carbon-intensity-crude-oils (HCICOs) and non-HCICOs. Instead, the proposal would eliminate the distinction entirely and simply require refiners to account for the difference in actual crude carbon intensity values that occur over time relative to a specified baseline. Thus, this would eliminate the “either/or” approach in the current provision and replace it with a continuum-based approach. In the discussion below, we refer to the crude treatment in the current regulation as the “current provision” and the proposed changes as the “California Average Approach.”

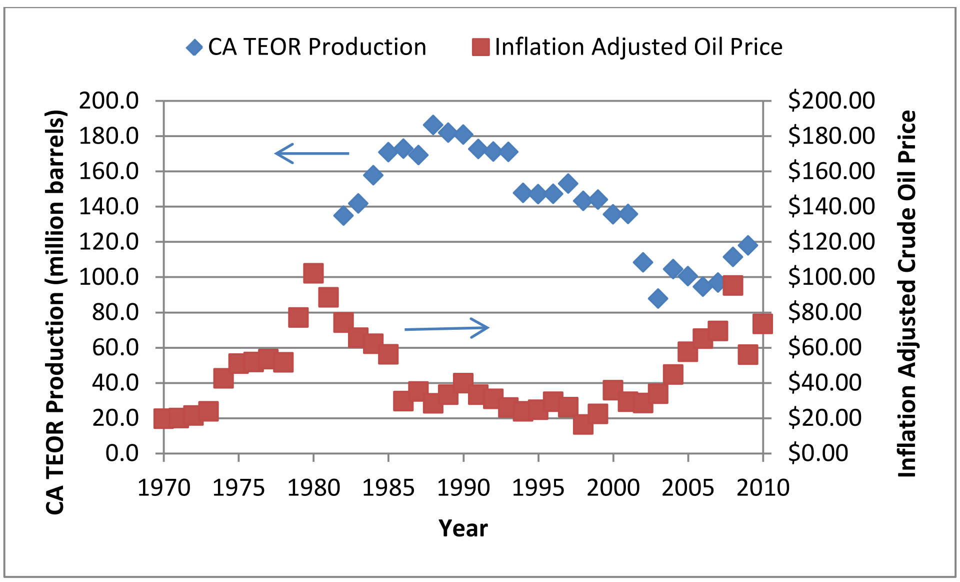
The California Average Approach provides a much more accurate accounting for GHG emissions from all crude oil used by California refineries. This more accurate accounting is necessary to prevent the possibility for backsliding in GHG emissions reductions, which could occur under the current provision. First, by removing the distinction between basket and non-basket crudes, the California Average Approach accurately accounts for emissions associated with increasing production of the basket crudes. Under the current provision, basket crude oil that uses high intensity production methods is assigned the average CI for basket crudes of 8.07 gCO_2e/MJ. Under the California Average approach, this crude would be assigned a CI value more representative of its actual emissions.

Second, the California Average Approach removes the HCICO threshold (15 gCO_2e/MJ) for non-basket crudes. Under the current provision, a non-basket crude with a CI of 14 gCO_2e/MJ will be assigned a CI of 8.07 gCO_2e/MJ, and the excess GHG emissions will not be mitigated. Under the California Average approach, this crude would accurately be assigned a CI of 14 gCO_2e/MJ. This differentiation in carbon intensity values for all crudes may be important because not all crudes produced using thermally enhanced oil recovery (TEOR), mining, or upgrading will have carbon intensity values above 15 gCO_2e/MJ. Moreover, unconventional production methods – such as gas-to-liquids, or enhanced oil recovery methods, such as CO_2 injection, hydrocarbon injection, and chemical injection – and conventional primary or secondary recovery with excessive flaring may also have higher than average CI values that are less than 15 gCO_2e/MJ.

Third, the California Average Approach captures expected increases in emissions intensity of producing conventional crudes as current fields become depleted. The current regulation does not account for GHG emissions increases in conventional crude production unless the CI reaches the unlikely level of 15 gCO_2e/MJ. Further discussion of the implications of more accurate GHG emissions accounting are provided below.

Under the current crude oil provision, there is significant potential for backsliding in the emissions reduction benefits of the regulation due to the grandfathering of basket crude sources. The current crude oil provision was written with the assumption that the use of high-intensity crude from basket sources would likely decrease between 2010 and 2020. This assumption was based on California thermally-enhanced crude (CA TEOR) being the primary source of high-intensity crude within the basket and the annual production of CA TEOR declining significantly from 1990 through 2006 (see Figure 4). The 2006 data were the most recent available to staff on CA TEOR production at the time the current provision was written in 2009.

Figure 4: Trends in CA TEOR Production and Inflation Adjusted Crude Oil Price[58]



As depicted in Figure 4, CA TEOR production shows an overall decline over the past 20 years, but with periods of increasing production occurring in the 1980s and 2006 through 2009. The periods of increasing production correlate well with periods of high oil prices, with a time lag of a few years. High oil prices incent development of new

[58] Spreadsheet containing data from:

- CA TEOR production data from California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, Annual Reports of the State Oil and Gas Supervisor for years 1983 to 2010, available at: http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx
- Crude oil price data obtained from http://inflationdata.com/inflation/inflation_Rate/Historical_Oil_Prices_Table.asp

thermal production, which requires high up-front capital expenditure, and also allow for previously unprofitable wells to be brought back into service. These wells commonly require high steam-to-oil ratios and therefore are only profitable with high oil prices. Between 2006 and 2009, production of CA TEOR increased from 95 to 118 million barrels per year (an average rate of increase of 8 million barrels per year).

The International Energy Agency predicts that oil prices will remain high through 2020 with average prices remaining in the $90 to $100 per barrel range (or higher).[59] Therefore, it is likely that CA TEOR production will remain high and possibly continue to increase through 2020. If the very high growth rate observed over the period of 2006 to 2009 were to continue over the time period for the regulation, an additional 760 million barrels of high-intensity crude would be produced in California as compared to the assumed static 2006 baseline level (95 million barrels per year being maintained over the period of 2010 to 2020).

If refined in California, the current regulation would assign the average carbon intensity of 8.07 gCO_2e/MJ to this additional high intensity crude and therefore excess emissions associated with producing the crude would not be mitigated. If one assumes an average carbon intensity of 20 gCO_2e/MJ for high-intensity crude production, an additional 760 million barrels of high-intensity crude from basket sources would result in approximately 45 million metric tons GHG emissions that do not get mitigated. This is equivalent to approximately three times the expected GHG emissions reductions from the LCFS during the year 2020.

We note that it is not likely that this high growth rate in CA TEOR production will continue through 2020, as reserves of crude oil in California are becoming depleted, but the calculation does inform as to the potential magnitude of the problem and the need to amend the current crude oil provision.

The California Average Approach also improves the accounting of GHG emissions associated with conventional primary or secondary production, which are expected to increase over time. Because the carbon intensity of this crude will not likely exceed the 15 gCO_2e/MJ threshold, the crude will always be assigned a carbon intensity of 8.07 gCO_2e/MJ under the current provision. Therefore, the expected increase in carbon intensity for conventional crude production would go unmitigated under the current regulation.

Crude oil projections presented in the 2010 World Energy Outlook show that in the year 2020, crude recovery from fields currently in production will be in rapid decline and a third of the conventional crude oil will originate from fields yet to be developed and even yet to be discovered.[60] The carbon intensity of conventional crude production in 2020 will likely be greater than today because fields in decline become more carbon-intensive

[59] International Energy Agency, 2010, World Energy Outlook 2010, page 72.
[60] International Energy Agency, 2010, World Energy Outlook 2010, page 122.

as recovery progresses from primary to secondary to tertiary. For example, as fields become depleted, water injection rates increase as indicated by average water-to-oil ratios (WOR) in the U.S. and Canada in excess of 10. An increase in WOR from 3 to 15 results in approximately three times the GHG emissions for crude lifting and water reinjection.[61]

New production is also likely to be more carbon-intensive. Much of the new conventional production is occurring offshore from deep sea wells. Secondary production from deep sea wells using water injection can be very GHG-intensive. Also, offshore production and rapidly developed onshore production (e.g., Bakken field in North Dakota and Montana) is often accompanied by excessive flaring.

By accurately accounting for carbon intensity of all crudes, the California Average Approach provides an incentive, all else being equal, for refiners in California to:

- Purchase crudes produced locally, as these crudes will have lower transportation emissions (more than 1 gCO_2e/MJ difference between crudes from South or Central America and those from Africa or the Middle East);
- Purchase crudes produced with low flaring emissions. Angola and Nigeria both produce light to medium sweet crudes, but flaring in Nigeria contributes over 6 gCO_2e/MJ more to GHG emissions; and
- Purchase thermally-recovered crudes that employ cogeneration or use a lower steam-to-oil ratio.

Although the market signal resulting from this incentive is likely small, it would grow if other jurisdictions adopt an LCFS program with similar provisions.

The regulation is currently structured so that the compliance schedule CI targets are based on average CI values for CaRFG (California Reformulated Gasoline) and ULSD (Ultra-Low-Sulfur Diesel). The CI of CaRFG reflects a mixture of 90 percent CARBOB and 10 percent California Average Corn Ethanol. The average Lookup Table CI values for CARBOB and ULSD are calculated using the average crude oil slate refined in California in the year 2006. Under the proposal, the portion of the CIs for CARBOB and ULSD due to the production and transport of crude oil used in California refineries will be updated to reflect crude supplies used in the most recent year currently available, which is 2009. In effect, this would:

- Increase the CI value attributable to the production and transport of crude oil from the current 8.07 gCO_2e/MJ to a higher value of 9.72gCO_2e/MJ, an increase of 1.65 gCO_2e/MJ;

[61] Jacobs Consultancy and Life Cycle Associates, 2009, Life Cycle Assessment Comparison of North American and Imported Crudes, prepared for Alberta Energy Research Institute.

- Change the base CI values for CARBOB, CaRFG, and ULSD from 95.86 gCO_2e/MJ, 95.85 gCO_2e/MJ, and 94.71 gCO_2e/MJ to 97.51 gCO_2e/MJ, 97.39 gCO_2e/MJ, and 96.36 gCO_2e/MJ, respectively; and
- Require a corresponding change in the annual LCFS standards to reflect a higher CI baseline for CaRFG and ULSD. These changes would apply to fuels supplied between 2013 and 2020.

The 1.65 gCO_2e/MJ increase in production and transport CI of California average crude oil under the proposal is comprised of three components:

- 0.5 gCO_2e/MJ is due to the change in calculation methodology. Applying the methodology used in the proposal to the 2006 crude data would result in a carbon intensity for crude recovery and transport of 8.57 gCO_2/MJ;
- 0.8 gCO_2e/MJ is due to the increase in CA TEOR production from 95 to118 million barrels per year between 2006 and 2009[62,63]; and
- 0.35 gCO_2e/MJ is due to the increase in non-basket HCICO imports from Canada, Venezuela, and Oman. Annual imports of Canadian oil sands and Venezuelan extra-heavy crude have increased between 2006 and 2009, from less than 5 million barrels to over 14 million barrels[64]. An additional small amount of TEOR from Oman was imported in 2009 but actual amounts are unknown.

The increase in CA TEOR production between 2006 and 2009 and related GHG emissions are "grandfathered" in the current approach under the "2006 basket" and therefore would have gone unmitigated regardless of the proposal. However, the current regulation would have required mitigation of the extra GHG emissions from use of the non-basket HCICOs imported from Canada, Venezuela, and Oman in 2009. The proposal provides disincentive for total thermal/mining/upgraded production to increase further, but will allow this additional high intensity crude to remain within the baseline. The overall effect of these factors is that the new 2009 baseline under the proposal would result in a CI increase of 0.35 gCO2e/MJ.

It should be noted that some of this increase in the baseline would be mitigated by the enhanced GHG benefits under the updated compliance schedules of the proposal. Because the revised baseline CI for CaRFG and ULSD is slightly higher (increase of 1.54 gCO_2e/MJ and 1.65 gCO_2e/MJ, respectively) than the current regulation, the ten percent reduction goal of the LCFS from these larger values will produce somewhat greater net emissions. For example, the relative gasoline and diesel CI-reduction

[62] California Department of Conservation, 2007, Division of Oil, Gas, and Geothermal Resources, 2006 annual Report of the State Oil and Gas Supervisor, page 3.
[63] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.
[64] California Energy Commission, October 11, 2011, Email Correspondence: Spreadsheet Data on Canadian and Venezuelan crude oil production.

requirements from the baseline through 2020 would each increase by 0.15 gCO_2e/MJ and 0.16 gCO_2e/MJ under the proposal. Further, the total deficits created with a 1.65 gCO_2e/MJ increase in crude oil CI are on the order of 3.5 percent (approximately 2.3 million MTs more deficits between 2013 and 2020). These effects enhance the GHG benefits expected from the LCFS program under the proposal.

Regulated Parties for Electricity

Staff is proposing modifications to the provisions in the regulation that designate which parties may opt-in as regulated parties for electricity. The proposed provisions clarify which parties are eligible to become regulated parties and receive credits for supplying electricity as a transportation fuel.

Although the proposed provisions alter the recipients of credits for electricity, they do not change the total number of credits that can potentially be generated. However, staff is proposing to include default parties who can potentially receive credits if the first-in-line designated party chooses not to become a regulated party by opting into the LCFS. Staff anticipates that including default parties in the regulation could potentially increase the number of credits captured and offered on the credit market for purchase, thereby decreasing the cost of purchasing credits and reducing compliance costs.

2. Impacts Analysis

    a. GHG and Air Quality Benefits

Opt-in and Opt-out Provisions

The proposed opt-in, opt-out provisions could potentially result in avoided emissions if a regulated party chose to purchase credits from an opt-in fuel producer to meet compliance obligations rather than create an additional demand for biofuels, resulting in the siting and building a new biorefinery.

Staff anticipates no further air quality benefits would result from the opt-in, opt-out regulation modifications.

Enhanced Regulated Party Provisions

As with the proposed opt-in, opt-out provisions described above, the enhanced regulated party provisions could potentially result in a greater number of parties who are eligible to generate credits registering for the regulation. The benefits of additional credits in the LCFS marketplace are similar to those described for opt-in, opt-out provisions.

Staff anticipates no further air quality benefits would result from the enhanced regulated party provisions.

Mandatory LCFS Reporting Tool Use

Staff anticipates no air quality benefits would result from the proposed mandatory LCFS reporting tool provision.

Credit Trading

Staff anticipates no air quality benefits would result from the proposed credit trading provisions.

Revised EERs

The modifications staff is proposing to EER values for electricity and fuel cell vehicles would result in a greater number of credits for regulated parties of these fuels. If the fuels were considered more attractive to regulated parties due to the increase in total credit value, it is conceivable that some shift in fuel use could occur. Because both electricity and hydrogen meet the 2020 carbon intensity standard, there could be air quality benefits if usage shifted from higher carbon intensity fuels.

Certification Process for Method 2A/2B

Staff anticipates no air quality benefits would result from the Method 2A/2B certification process provisions.

High Carbon Intensity Crude Oil (HCICO)

As explained below, staff believes that the proposal would provide a framework for enhanced GHG benefits, and that the proposal would not result in additional adverse impacts to California's air quality relative to the existing regulation.

The proposed changes to the handling of crude oil under the LCFS may result in an increase or a decrease in GHG benefits under the LCFS program, depending on projections for crude —specifically, California crudes – supplied to California refineries. Under the current regulation, an increase in California TEOR production would not have to be mitigated because it is grandfathered crude; therefore, the current regulation would be less protective than the proposed amendment, which would account for additional HCICO, domestic or imported. Conversely, if California TEOR production declines by 2020 and is replaced by imported HCICO, the current regulation would impose a CI penalty on the imported HCICO, whereas the proposed amendments would apply no such penalty as long as the total HCICO volume remains the same or declines. Finally, since the proposed amendment will assign lower CI values for California non-TEOR crudes (i.e., a true accounting of crude CIs), their use could mitigate the additional GHG impacts incurred by the additional use of crudes from TEOR production.

Overall, staff believes that the proposed revisions are necessary to properly account for the CI values of all crudes processed in California, irrespective of source. The current regulation does not accomplish this, and grandfathered “basket “crudes that are HCICO could increase in production with no mitigation required, thereby reducing the effectiveness of the LCFS during the remaining period (2013 to 2020) of the LCFS program.

The proposed 2009 baseline CI is slightly higher than the 2006 baseline, so additional volumes of imported, higher-CI crudes may be processed in California refineries. However, since the ten-percent reduction goal of the LCFS will produce greater net GHG emissions reductions under the proposal—10 percent of a larger number is also a larger number—some of the impacts of the higher baseline CI will be mitigated. For example, the potential incremental GHG benefits under the revised compliance schedules are estimated to be about 259,000 MT CO_2e in 2020; therefore, the total GHG emissions reductions for the LCFS in 2020 are estimated to be about 16.1 MMT CO_2e instead of the original 15.8 MMT CO_2e.

Staff expects the proposed HCICO provisions to result in no additional adverse impacts to California’s air quality due to criteria and toxic air pollutants relative to the current regulation. Based on stringent New Source Review regulations affecting the permitting of these facilities, staff recommends that emissions from these facilities be mitigated and offset pursuant to local air district and CEQA requirements.

Regulated Parties for Electricity

Staff anticipates no air quality benefits would result from the modifications to the regulated parties for electricity.

b. Other Potential Impacts

Based on ARB’s review of the proposed regulation, staff concludes that the regulation would not have a significant adverse effect on the environment as explained below. No discussion of alternatives or mitigation measures is necessary because there are no significant adverse environmental impacts identified.

Compliance with all the proposed amendments would not require or result in any physical change to the existing environment, that might involve new development or require modifications to buildings or other structures, or affect operations at existing facilities, or cause any new land use designation. Therefore, these provisions are not expected to result in any adverse impacts to aesthetics, air quality, agricultural and forestry resources, biological resources, cultural resources, geology and soils, greenhouse gases, land use planning, mineral resources, population and housing, public services, recreation, or traffic and transportation. Further, compliance with the proposed modifications to the LCFS does not involve any activity that would involve or affect hazardous material, hydrology and water quality, noise, or population and housing because they do not mandate any action that could affect these resources.

E. Environmental Justice

ARB is committed to integrating environmental justice in all of its activities. On December 13, 2001, the Board approved "Policies and Actions for Environmental Justice," which formally established a framework for incorporating Environmental Justice into ARB's programs, consistent with the directive of California state law.[65] Environmental Justice is defined as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.

The proposed amendments to the LCFS regulation are consistent with the environmental justice policy to reduce health risks from GHG emissions in all communities, especially those with low-income and minority populations, regardless of location. The proposed amendments will continue to reduce GHG emissions from the use of transportation fuels in California.

AB 32 requires that, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emission limit, ARB must consider the potential for direct, indirect, and cumulative emission impacts from market-based compliance, including localized impacts in communities that are already adversely impacted by air pollution, design the program to prevent any increase in emissions, and maximize additional environmental and economic benefits prior to the inclusion of market-based compliance mechanisms in the regulations. As ARB further develops its approach for consideration of these issues, staff will continue to consult with outside experts.

[65] Air Resources Board, 2001, Policies and Actions for Environmental Justice

VI. ECONOMIC IMPACT ANALYSIS

In this chapter, ARB staff analyzed a number of proposed LCFS regulation amendments (as outlined below) and estimated their potential fiscal and economic impacts. The economic analysis includes the costs and savings associated with the economic impacts on businesses, consumers, and government agencies. For a full description of each of the proposed regulatory amendments, please see Chapter IV.

A. Legal Requirements

This section explains the legal requirements that must be satisfied in analyzing the economic impacts of the regulation. Section 11346.3 of the Government Code requires State agencies to assess the potential for adverse economic impacts on California business enterprises and individuals when proposing to adopt or amend any administrative regulation. The assessment shall include a consideration of the impact of the proposed regulation on California jobs, business expansion, elimination or creation, and the ability of California businesses to compete with businesses in other states. Also, State agencies are required to estimate the cost or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance. The estimate shall include any non-discretionary cost or savings to local agencies and the cost or savings in federal funding to the State. Finally, Health and Safety Code section 57005 requires ARB to estimate the economic impacts of submitted alternatives to a proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding ten million dollars in any single year. The following is a description of the methodology used to estimate costs as well as ARB staff's analysis of the economic impacts on California businesses, consumers, and government agencies.

B. Summary of the Economic Impacts

<u>Opt-in, opt-out provisions</u>

Staff will provide clarity to opt-in and opt-out procedures, which could encourage the regulated parties to opt-in, resulting in greater number of LCFS credits generated and available for use by regulated parties. If a regulated party selects to opt-out, then all the available generated credits by the regulated party shall be retired.

Economic Impact: Greater number of LCFS credits generated and available for use could reduce the cost of LCFS credits, thereby reducing compliance costs.

<u>Enhanced Regulated Party Provisions</u>

Allows out-of-state fuel producers and distributors to qualify as regulated parties and generate credits, which could result in greater number of LCFS credits available for use for compliance.

Economic Impact: Greater number of LCFS credits generated and available for use could reduce the cost of LCFS credits, thereby reducing compliance costs.

Mandatory LCFS Reporting Tool Use

Proposed regulatory amendment will require regulated parties to use only the LCFS Reporting Tool (LRT) as the “interactive, secured internet web-based form” required by the current regulation.

Economic Impact: Staff expects no economic impact, as regulated parties are already using the LRT exclusively to comply with LCFS reporting requirements.

Credit Trading

Staff is proposing to add provisions in the regulation that clarify how credits and deficits are tracked and to specify the process to be used to acquire, bank, transfer, and retire credits. In the proposal, staff is also including a provision that allows a regulated party to acquire credits in the first quarter of a year to meet a compliance obligation in the previous year, as long as those credits were generated in a previous year. This proposal further seeks to establish requirements relating to the public release of information concerning the generation of deficits and the generation, use, and transfer of credits.

Economic Impact: By adding certainty to the credit market, credit transactions should increase, thereby lowering the cost of compliance. Both credit sellers and buyers will be more likely to carry out transactions within a rational and predictable framework, improving the efficiency of the LCFS credit market.

Revised EERs

Staff is proposing three modifications to the Energy Economy Ratios (EERs). First, staff is proposing to add to the regulation an EER of 1.0 for heavy-duty compression-ignited engines fueled with compressed natural gas (CNG) or LPG. Currently, the EER in the regulation for these vehicles is 0.9. Second, staff is proposing to change the EER for the electricity used in light-duty battery electric vehicles and plug-in hybrids from 3.0 to 3.4. Third, staff is proposing to change the EER for light-duty fuel cell vehicles from 2.3 to 2.5.

Economic Impact: The proposed changes to EER values have the potential to increase the number of credits generated for CNG/LNG, electricity, and hydrogen transportation fuels. An increase in the number of credits available for regulated parties to purchase can decrease the value of a credit, potentially decreasing compliance costs.

Certification Process for Method 2A/2B

In the current regulation, the process through which a regulated party receives approval to use a carbon intensity value determined through the Method 2A/2B process requires an Executive Officer (EO) or Board hearing. Staff is proposing to convert this regulatory process to a certification process to save staff resources, yet maintain the technical rigor and public input of the current requirements.

Economic Impact: The Method 2A/2B application requirements and the technical analyses conducted by staff during the review of those applications will remain unchanged; therefore, there should be no economic impact on the regulated parties related to the proposed certification process. The benefit of the proposed certification process is a streamlined approval process that reduces staff resources, which then can be redirected to other tasks and program needs. This fiscal cost effects are discussed below in section D.2.

High CI Crude Oil (HCICO)

The proposed LCFS high carbon intensity crude oil (HCICO) amendment departs from the existing HCICO provisions in two fundamental ways. It establishes a new baseline consisting of the 2009 crude mix processed by California refineries, and it assigns a single average CI to every crude oil refined into transportation fuel for sale in California. This California average crude CI would be calculated annually and would apply to the reporting period following its calculation. For example, data for the 2012 crude slate would become available sometime in 2013, at which the California average crude CI would be calculated. This California average crude CI would become applicable on January 1, 2014.

This California average approach to HCICO accounting would replace the existing approach which established a California "basket" containing the crudes processed by California refineries in 2006. The average CI calculated for that basket (8.07 gCO_2e/MJ) was assigned to all crudes contained therein. All crudes *not* in the 2006 basket were to be screened to identify those which are clearly not HCICOs, and those which have the *potential* to be HCICOs. Regulated parties using crudes in the latter category would be required to formally estimate the CI of those crudes using the LCFS Method 2B process. If a Method 2B analysis revealed that the extraction and transportation components of the resulting CI exceeded 15 gCO_2e/MJ, the affected crudes would be deemed to be a HCICO, and would be assigned the CI estimate from its Method 2B analysis.

A shortcoming with the original proposal was that an accurate CI accounting was only required for crudes that exceeded the threshold value of 15 gCO_2e/MJ. Crudes contained in the 2006 basket and crudes with extraction and transportation CIs below the 15 gCO_2e/MJ threshold were able to use the baseline mix CI of 8.07 gCO_2e/MJ. The adoption of the California average approach addresses this shortcoming.

The proposed California Average approach fully accounts every year for the carbon intensity of all crudes processed by California refineries selling transportation fuel into the California market. However, because the California Average approach assigns a single average value to the whole California crude slate, individual refineries processing crudes with CIs that are above the California average will realize a benefit by not having as large a CI deficit to mitigate, while those with CIs that are below the State average will experience a cost by sharing the mitigation of higher-CI crudes that they did not process.

The crude purchasing incentives created by the California average approach vary according to a number of factors. All refiners, however, share the same basic incentive to maintain the California average year-over-year.

Cost Impacts to Fuel Producers

As a result of the differences described above, the HCICO purchasing incentives created by proposed amendments are quite different from the incentives that exist under the current provisions. Under the proposed amendments, the costs incurred depend upon how refiners respond to two potentially competing incentives: the financially driven desire to purchase suitable crudes at least cost and the desire to maintain the California Average. At times, a refinery may find it advantageous from a business perspective to run a HCICO. Doing so, however, risks increasing the California Average. Increases in the California Average must be mitigated by offsetting purchases of lower-CI fuels or the use of credits.

Understanding this dynamic requires that we first understand the case in which the California average is maintained. The proposed California Average approach provides California fuel producers with a number of opportunities to maintain the California Average CI.

1. By using a 2009 baseline, the proposed approach provides more flexibility to fuel producers than does the 2006 baseline used in the existing regulation. Since the 2009 baseline contains higher levels of HCICO than the 2006 baseline, it would allow more flexibility to fuel producers when considering the purchase of higher volumes of HCICOs.
2. The proposed California Average approach provides refiners with the flexibility to substitute one HCICO for another. A HCICO from a newly developed source, such as Canada for example, could be substituted for HCICO from a declining source, such as Venezuela. Under the existing provisions, this substitution would constitute a change from a grandfathered basket crude to a HCICO, triggering an increase in the refiner's CI. This ability to switch among differing HCICOs while maintaining a constant HCICO volume and a constant California Average provides refiners with significant flexibility—flexibility that is unavailable under the current HCICO provisions.
3. Under the proposed amendment, all crudes—including non-HCICOs—are assigned an appropriate and current average value. Under the existing provisions,

non-HCICOs with actual CIs of 15 gCO_2e/MJ or less are assigned a CI of 8.07gCO_2e/MJ. A significant proportion of the California crude slate may fall into this category. The annual California average that would be calculated under the proposed amendment would include the actual CIs of this category of crude oils. These low-CI crudes would at least partially offset the HCICO CIs also included in the average.

The use of a 2009 baseline, the ability to substitute HCICOs without penalty, and the inclusion of low-CI crudes in the California average will result in compliance costs that are no higher than the costs of complying with the existing HCICO provisions. Due to the increased flexibility introduced by the proposed amendments, compliance costs could be lower than they would be under the existing provisions.

Having covered the case in which the California average is maintained year-over-year, it is now necessary to discuss the case in which the California average rises due to a net increase in HCICO purchases. The resulting increase in the average crude CI would need to be mitigated through the increased use of lower-CI fuels and, possibly, the use of credits.

A comparison of the existing and proposed HCICO provisions under a rising average CI scenario requires an examination of the cost impacts of in- and out-of-basket crudes:

1. Crudes that are outside of the California basket.

   Under the current regulation, any HCICO from outside of the California basket results in a CI penalty (in the form a mitigation requirement). Under the proposed amendment, however, some of the non-basket HCICO purchases could be offset by decreases in purchases of in-basket HCICOs. Such offsets will not always occur, of course, but, over the long run, enough offsetting purchases would occur to lower the cost of compliance of under the proposed amendments relative to compliance costs under the existing provisions.

2. Crudes that are in the California basket.

   Unlike the existing provisions, the proposed amendments would require all increased purchases of in-basket HCICOs to be included in the calculation of the California Average. Generally, this represents an increased cost of compliance, which would partially or wholly offset the decreased compliance costs realized for out-of-basket crudes (see section (a), above). In practice, however, reduced purchases of out-of-basket HCICOs would act to reduce the upward pressure from the in-basket purchases. Under the existing provisions, the benefits of reduced purchases of out-of-basket HCICOs would accrue only to the refiners reducing their HCICO use.

Potential Cost Savings

As mentioned above, the current LCFS regulation requires regulated parties using crudes that are "potential-HCICOs" (i.e., those that did not pass the first screening process that would have identified them as clearly non-HCICO) to formally estimate the CI of those crudes using the LCFS Method 2B process. Based on staff experience to date with the Method 2A/2B process, staff estimates that a 2B application would cost the applicant about $20,000. Since 65 market crudes out of 255 did not pass the initial screening process, at $20,000 apiece for a Method 2B application, total costs could be as high as $1.3 million if all of these crudes needed CI values for California use. Under the proposed amendments, ARB staff will calculate the California average crude CI, obviating the need for regulated parties to go through the Method 2B process.

Summary

Where the existing provisions strongly discourage the purchase of out-of-basket HCICOs while simultaneously allowing unlimited, penalty-free purchases of in-basket HCICOs, the proposed amendments generally dis-incent *all* HCICO purchases by all refiners. The differences created by the removal of the California basket under the proposed amendments make any comparison between the existing and proposed provisions a complex undertaking. The analysis presented in this chapter shows, however, that the 2009 baseline, the ability to substitute HCICOs without penalty, and the inclusion of low-CI crudes in the proposed California average will tend to contain compliance costs. Compliance costs under the proposed amendments will be no higher than compliance costs under the existing provisions. The added flexibility that would be created under the proposed amendments could result in reduced compliance costs.

<u>Regulated Parties for Electricity</u>

Staff is proposing modifications to the provisions in the regulation that designate which parties may opt-in as regulated parties for electricity. The proposed provisions clarify which parties are eligible to become regulated parties and receive credits for supplying electricity as a transportation fuel.

Although the proposed provisions alter the recipients of credits for electricity, they do not change the total number of credits that can potentially be generated. However, staff is proposing to include default parties who can potentially receive credits if the first-in-line designated party chooses not to become a regulated party by opting into the LCFS.

Economic Impacts: Staff anticipates that including default parties in the regulation could potentially increase the number of credits captured and offered on the credit market for purchase, thereby decreasing the cost of purchasing credits and reducing compliance costs.

C. Methodology for Estimating Costs

As discussed above, most of the proposed amendments to the LCFS regulation will not result in any fiscal or economic impacts. Staff asserted that several of the proposed amendments would result in additional credits being generated and used within the LCFS program, thereby reducing the cost of credits and reducing compliance costs. Staff did not and could not quantify the benefits of additional available LCFS credits; however, basic economic principles of supply-and-demand support staff's assertions.

D. Potential Costs to Local, State, and Federal Agencies

Fiscal Impact on State, Local, and Federally-Funded Programs

There are no fiscal impacts on these programs.

Other Fiscal Effects on Government

Method 2A and 2B pathway carbon intensities are currently approved through the regulatory change process. Final approval is granted by the Executive Officer at a public hearing. Staff proposes to streamline the approval process by converting the regulatory process to a certification process, thereby reducing staff resources, which then can be redirected to other tasks and program needs. ARB currently runs several effective certification programs, including programs to certify diesel control devices and distributed generation equipment. Staff's proposed certification program will maintain the technical rigor and public input of the current regulatory process, yet realize significant staff utilization efficiencies as estimated in Table 6 below:

Table 6. Fiscal Effects of a Regulatory Change Process

					Totals	
Classification	**Annual PY cost [a]**	**Low Hourly Personnel Cost**	**High Hourly Personnel Cost**	**Grand Total Hours devoted to Reg. Change**	**Low**	**High**
Air Pollution Specialist [b]	\$107,000 - \$164,000	\$60	\$92	272	\$16,345	\$25,183
Air Resources Engineer [b]	\$118,000 - \$172,000	\$66	\$97	368	\$24,355	\$35,572
Air Resources Supervisor 1 [c]	\$156,000 - \$181,000	\$88	\$102	111	\$9,753	\$11,301
Air Resources Supervisor 2 [c]	\$167,000 - \$195,000	\$94	\$110	63	\$5,934	\$6,899
AGP Video Coordinator [c][d]	N/A	N/A	N/A	N/A	N/A	\$6,700
2 Associate Government Program Analyst [c][d]	\$110,000 - \$124,000	\$62	\$70	10	\$617	\$700
2 Students [c][d]	N/A	\$13		8	\$104	\$104
Court Reporting Services [c][d]	N/A	N/A	N/A	N/A	\$250	\$800
Grand Totals					\$57,582	\$87,503

[(a)]: The total costs include salaries and wages, benefits, operating expenses and equipment.
[(b)]: Information provided by ASD
[(c)]: Using data from ARB
[(d)]: Data provided by ARB

VII. ANALYSIS OF ALTERNATIVES

This Chapter provides an analysis of the alternatives to the proposed amendments to the Low Carbon Fuel Standard (LCFS) regulation. The Chapter is divided into two sections. The first section represents an analysis of the status quo alternative—that is, the “no action” alternative. The second section addresses specific alternatives to staff’s proposed amendments. A detailed discussion of each alternative considered follows in the subsections below.

A. “No Action” Alternative

One of the alternatives to the proposed regulatory amendments is to keep the current LCFS regulation as is (i.e., “no action” alternative). ARB staff evaluated this alternative, the analyses of which are summarized below:

1. Energy Economy Ratios (EERs)

Since the publication of the ARB's original LCFS ISOR in March 2009, new fuel economy data have become available for alternative-fueled vehicles. Not revising the EERs values to reflect the most current energy efficiency data available for actual vehicles available in today’s market would result in the LCFS regulation being out-of-date on emerging vehicle technologies. Staff’s proposal to update the EERs values for CNG/LNG burning heavy-duty vehicles and for light-duty vehicles in the battery electric vehicle, plug-in hybrid, and fuel cell-powered categories would reflect current 2011 powertrain efficiencies that were unavailable in 2009 for commercially available cars and heavy duty vehicles.

2. Regulated Party Revisions

Under the current LCFS regulation, a regulated party is defined as a person who ultimately ends up with the carbon intensity obligation for the fuels introduced into the market. Upstream fuel producers and distributors are not regulated parties and therefore cannot generate and maintain LCFS credits, and they are not required to report their fuel sales in the LCFS Reporting Tool (LRT). This current provision may obscure the understanding of the complete lifecycle of imported blendstocks and prevent fuel producers from realizing the full market value of their fuels by disallowing LCFS credit generation. Staff’s proposal would allow upstream producers and distributers to voluntarily opt into the LCFS as regulated parties, reducing fuel pathway uncertainties and generating additional credits for compliance purposes.

3. Reporting Requirements

The current regulation mandates the use of “an interactive, secured internet web-based form” for submitting annual compliance and quarterly progress reports. Since regulated parties are already using the LRT to report, a “no action” alternative to this proposed amendment would not have a real impact today; however, designating the LRT as the mandated reporting form minimizes potential confusion regarding future LCFS reporting.

4. Method 2A/2B Certification

In the current regulation, the process through which a regulated party receives approval to use a carbon intensity value determined through the Method 2A/2B process requires an Executive Officer or Board hearing. This regulatory approach requires considerable staff resources better utilized for other high-priority tasks and programs. Staff is proposing to convert this regulatory process to a certification process to save staff resources, yet maintain the technical rigor and public input of the current requirements. To maintain the current regulatory approach would forfeit the opportunity for greater staff efficiency and productivity.

5. Credit Trading

The current regulation is silent on the mechanism through which LCFS credits may be traded in a robust market, which is essential to the success of the LCFS program. The proposed amendments of the LCFS regulation include a new section to provide more detail on how credits and deficits will be tracked, and to specify the process to be used to acquire, bank, transfer and retire credits. In the proposal, staff is also including a provision that allows a regulated party to acquire credits in the first quarter of a year to meet a compliance obligation in the previous year, as long as those credits were generated in a previous year. This proposal further seeks to establish requirements relating to the public release of information concerning the generation of deficits and the generation, use, and transfer of credits. The “no action” alternative to clarifying the credit trading provisions of the LCFS through proposed regulatory amendments would continue to obscure and inhibit the LCFS credit market.

6. Opt-In/Opt-Out Procedure

The current LCFS regulation allows electricity, hydrogen, CNG, LNG, and biogas to opt in to generate credits. It simply refers to a regulated party electing to generate LCFS credits for the exempted fuels but provides no specificity on how to opt-in or opt-out. There are a number of providers of biogas and other exempted, low-CI fuels (those that already meet the 2020 CI standards) who want to opt into the LCFS but are reluctant to do so because the current regulatory language does not specify what requirements are necessary to opt-out in the future. The proposed amendments to the LCFS regulation include additional language that details how a fuel provider could become a regulated party (opt-in) or later remove them from being a regulated party (opt-out). Providing such specificity should encourage providers of exempt, low-CI alternative fuels who have been reluctant or uncertain about bringing credits to the LCFS market to opt-in. Staff deemed such a proposed amendment necessary and preferred over the current regulation.

7. Regulated Party for Electricity

Since the LCFS was approved by the Board in April 2009, the market dynamics for electric vehicles (EV) and EV-fueling infrastructure have evolved. In the current LCFS regulation, regulated party language for electricity is obsolete and incomplete, needs clarification of key terms, and should reflect current business models for the deployment of EVs. Staff proposes regulatory amendments to clarify which parties are eligible to become regulated parties and receive credits for supplying electricity as a transportation fuel. The "no action" alternative to the proposal would simply maintain the ambiguity and obsolescence of the current language.

8. High Carbon-Intensity Crude Oil (HCICO)

The current LCFS regulation recognizes that additional energy is required to produce some crude oils and, taking a full lifecycle assessment (LCA) into consideration, calculates the carbon intensity deficit for such high carbon intensity crude oils (HCICOs) processed in California refineries. The HCICO provision in the current regulation has been of particular concern for the oil industry, which asserts that the current HCICO provisions result in economic harm to California refineries and environmental harm overall due to crude "shuffling." On the other hand, other stakeholders are equally as adamant that the LCFS should continue to prevent increases in lifecycle carbon emissions that could occur if higher intensity crudes are used to replace existing supplies. These parties generally support approaches that discourage or fully mitigate the refining of HCICOs in California and incentivize carbon emission mitigation techniques for oil production.

ARB staff has worked with all interested stakeholders to explore alternatives to the current adopted approach to addressing HCICO in the LCFS. Staff proposes regulatory amendments that would more appropriately account for additional emissions from the production and transportation of HCICO processed in California refineries and therefore meets the intent of the regulation (to ensure that the LCFS benefits are not diminished due to increases in GHG emissions from higher carbon intensity crude supplies). At the same time, the staff's proposal addresses, to the extent possible, the concerns laid out by the various stakeholders.

The "no action" alternative of keeping the current provision has several drawbacks. First, there is the possibility for backsliding in the emissions reduction benefits of the LCFS due to the grandfathering of basket crude sources under current provisions. Second, the current approach limits refiners' flexibility to purchase crude supplies, as they will have significant incentives to avoid using fuels classified as HCICOs. Third, the current approach is overly burdensome to the regulated parties who need to undergo a technical rigorous Method 2B process for establishing CIs for their HCICOs and obtain approval of the Executive Officer.

9. Designating the LRT for LCFS Quarterly and Annual Reporting

As noted, the alternative to the staff's proposal is the existing regulatory language, "[a] regulated party must submit an annual compliance and quarterly progress report by using an interactive, secured internet web-based form." [Emphasis added.] While this performance-based alternative appears flexible, it has a number of issues that are addressed by the proposal. First, the current language provides little guidance to regulated parties as to what exactly would constitute a compliant interactive, secured internet web-based form. As with most industries, the transportation-fuels sector values certainty, and specifying that only the LRT, which is accessible from ARB's website, can be used for reporting ensures such certainty.

For similar reasons, the requirement to use the LRT ensures standardization and consistency, which would help facilitate credit trading between regulated parties (especially when the LRT version 2.0 is developed, which will automate credit trades and credit reporting). On the other hand, having multiple types of software used for reporting purposes would likely entail compatibility and security issues, both with ARB's database and with credit trading partners.

Finally, because all regulated parties are using the LRT and ARB makes it available for free, there are no additional costs involved with using the LRT for regulated parties. By contrast, the purchase of and training with different, commercially-developed reporting software would almost certainly involve additional costs for regulated parties.

For the above reasons, staff determined that prescribing the use of the LRT as the only online mechanism for use by regulated parties is superior to allowing multiple types of software under the current performance standard.

B. Alternatives to Specific Proposed Amendments

1. Regulated Party for Electricity

Staff evaluated the following options for designating the potential electricity regulated parties:

- Designate electric utilities as potential regulated parties for all EV charging.
- Designate EV owners as potential regulated parties for electricity delivered to their vehicles.
- Omit potential default regulated parties.

When evaluating these alternatives, staff kept three goals in mind. The first goal was to keep the proposed language simple to avoid confusion in regulated party designation and maintain relevancy as the EV-charging market evolves in future years. The second goal was to limit the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties. The final goal was to maximize the number of credits captured and available for purchase.

The first option – designate electric utilities as potential regulated parties for all EV charging – goes against the goal of maintaining relevancy as the EV charging market evolves in future years. Such designation cannot benefit potential charging equipment installers such as non-utility electric vehicle service providers, business owners, and EV fleet owners; therefore, this approach would discourage their efforts to establish the public and private charging networks which are critical to the future EV market.

The second option – designate individual EV owners as potential regulated parties for electricity delivered to their vehicles – goes against the goal of limiting the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties. It is much more difficult to keep track of the credits from individual EV customers than from larger entities, such as the utilities.

The third option – designate a hierarchy of potential regulated parties without designating a default party – goes against the goal of maximizing the number of credits captured and available for purchase. Given the recordkeeping and other requirements in the LCFS regulation, there is a potential for significant amounts of credits to be "orphaned" or otherwise not captured and put into the credit trading market if the designated regulated party, such as a business owner with an onsite charger, fails to opt in. On the other hand, electric utilities have an inherent interest in being able to generate credits for electricity used for transportation. For this reason, among others, staff proposes to designate electric utilities as the default regulated party to ensure that credits are not orphaned.

2. High Carbon-Intensity Crude Oil (HCICO)

This section includes a discussion of the potential approaches to the treatment of HCICOs in the LCFS regulation, staff's recommended approach, and the rationale for not choosing any of the alternatives.

Potential Approaches

Outlined below are several alternative approaches for the treatment of HCICOs in the LCFS regulation that were explored as this proposed rulemaking was developed. These approaches are a combination of those suggested by stakeholders or identified by ARB staff. An alternative that involves clarifying amendments to the current approach is presented first followed by discussion of five alternatives that would involve significantly different conceptual approaches.

1. Current Approach with Amendments

This approach provides amendments to clarify the regulation requirements and provides details for implementation. Amendments are based on the draft Crude Screening proposal that has been used to generate the list of non-HCICO sources attached to Regulatory Advisory 10-04A. The amendments would:

a. Include Step 1 of the screening process to codify the method used to generate the non-HCICO list. The non-HCICO identifiers are:

- Crude oil produced using recovery techniques other than thermal enhanced oil recovery (steam/hot water injection or in-situ combustion) or crude bitumen; and
- Crude oil produced from a country with an average flaring rate of less than 10 scm/bbl, as determined using the most recent NOAA/NGDC gas flaring rate data together with annual oil production data.

b. Include a provision that a regulated party will not be retroactively penalized if a crude source that has been added to the non-HCICO list is later removed;

c. Include language which sets an interim default HCICO CI for non-baseline crudes that are not on the non-HCICO list (i.e., "potential HCICO");

d. Briefly outline the process by which a regulated party must get a crude source that "fails" the initial screen either added to the non-HCICO list or determined to be HCICO; and

e. Include a provision that a regulated party can retroactively use the average CI in place of the default HCICO CI if a crude source is later determined to be non-HCICO and put on the non-HCICO list.

2. California Average Approach

In this approach, the base deficit is calculated the same as in the current approach. However, an incremental deficit is applied to all companies if the average crude slate refined in California becomes more carbon intensive over time. This allows for an individual company to shift its crude slate and not be required to mitigate increased emissions as long as the average CI of the California crude slate used by the industry as a whole does not increase over time relative to the baseline year. For the California crude refining industry:

a. Each year of the regulation, a "current" California average CI would be calculated using the crude slate refined in California during a prior year.

b. If the "current" California average CI is greater than the "baseline" California average CI, then a revised incremental CI would be established and all regulated parties that provide California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) and ULSD would incur greater incremental deficits proportional to the amount of fuel they supplied and the difference between the current CI and the baseline CI.

c. An individual company could earn credits if it purchases crude from sources that have implemented innovative methods, such as carbon capture and sequestration (CCS) to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

A variant of this approach[66] could provide the regulated parties the option to report company-specific CI values through an approach analogous to the Hybrid Approach discussed below instead of being subject to the California average CI value in a given year. Those companies opting to report company-specific CIs would be excluded from the California average CI calculation for that year. Any credit generation opportunities would be premised on a company choosing to report their own company specific baseline.

3. Hybrid California Average/Company Specific Approach

The base deficit for individual companies is calculated the same as in the current approach. However, individual companies only incur an Incremental Deficit if their own crude slate becomes more carbon-intensive over time relative to their crude slate refined in the baseline year. This allows individual companies to shift the crude slate they refine in California and not be required to mitigate increased emissions as long as the average CI of their own crude slate does not increase. There are two ways of implementing this approach: by either regulating the volume or the CI of the HCICOs refined by a company. For each oil company:

a. A “baseline” volume (or CI) of HCICO would be determined using the crude slate refined by that company in California during the baseline year.
b. Each year of the regulation, a “current” volume (or CI) of HCICO would be calculated using the crude slate refined by that company in California during a prior year.
c. If the company’s “current” volume (or CI) of HCICO is greater than its “baseline” volume (or CI) of HCICO, then the company will incur an incremental deficit calculated using the difference between the current volume (or CI) and the baseline volume (or CI).
d. An individual company can earn credits if it purchases crude from sources that have implemented innovative methods, such as CCS, to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

4. Company Specific Approach

Each oil company will have distinct Lookup Table values and compliance targets for CARBOB and diesel, which are based on the crude slate refined by that company in California in the baseline year. Individual companies only incur an Incremental Deficit if their own crude slate becomes more carbon-intensive over time. This allows individual companies to shift their crude slates and not be required to mitigate increased emissions as long as the average CI of their own crude slate does not increase. For each oil company:

[66] Simon Mui, NRDC and John Shears, CEERT, September 17, 2011. Comment letter to ARB regarding HCICO Provisions.

a. Each year of the regulation, a "current" CI would be calculated using the crude slate refined by that company in California during a prior year.
b. If the "current" company-specific CI is greater than the "baseline" company-specific CI, then the company will incur an incremental deficit calculated using the difference between its current CI and its baseline CI.
c. An individual company can earn credits if it purchases crude from sources that have implemented innovative methods, such as CCS, to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

5. Worldwide Average Approach

This approach bases the average Lookup Table CI values for CARBOB and diesel and the compliance schedule on worldwide average crude oil production and refining emissions in the baseline year. A Base Deficit is calculated using the difference between the average Lookup Table values for CARBOB (or diesel) and the compliance target for the current year. An Incremental Deficit is applied to all companies if the worldwide average crude production and refining becomes more carbon intensive over time.

All producers of CARBOB and diesel will calculate a Base Deficit using the difference between the average Lookup Table value for CARBOB or diesel and the compliance target in that year. Each year of the regulation, a "current" worldwide average CI would be calculated using the crude slate produced and refined worldwide during the previous year. If the "current" worldwide average CI is greater than the "baseline" worldwide average CI, then all companies will incur an incremental deficit calculated using the difference between the current CI and the baseline CI.

A variant of this approach[67,68] bases the average Lookup Table CI values for CARBOB and diesel and the compliance schedule on California average crude oil production and refining emissions in the baseline year. The other provisions remain the same.

6. California Baseline Approach (Eliminate Consideration of HCICOs in the LCFS)[67,68]

All CARBOB and diesel would use the existing CI values in the Look-Up Table. Regulated parties would only calculate and be subject to the Base Deficit for all CARBOB and diesel regardless of the crude oil used for refining. The Look-Up Table values for CARBOB and diesel would not be updated.

[67] Catherine H. Reheis-Boyd, WSPA, August 8, 2011. Comment letter to ARB regarding LCFS Regulatory Amendments.
[68] Ralph J. Moran, BP America, Inc., July 26, 2011. Comment letter to ARB regarding HCICO Provisions.

Evaluation of Potential Approaches

ARB staff evaluated the potential approaches for regulatory amendments. The guiding principles that formed the basis for our assessment of the alternatives are outlined below. These principles we chosen to assess if the core objectives that lead to the creation of the existing HCICO provision would be preserved.

1. Key Guiding Principles

   a. *Accurate accounting for emissions from production and transport of crude oil:* Since the LCFS regulation takes into account full lifecycle GHG emissions for fuel pathways, including all stages of feedstock production and distribution, the upstream emissions from energy-intensive crude recovery methods need to be accounted for to provide consistent treatment versus other regulated fuels. Establishing an accurate performance-based accounting system will ensure that additional emissions in the carbon intensity of gasoline and diesel fuels from the baseline are captured.

   b. *Discouraging potential increases in emissions and ensure that increases that do occur are mitigated:* An incremental deficit for backsliding with respect to the baseline will ensure that the GHG emission contributions from petroleum fuels do not increase over time without being mitigated.

   c. *Promoting innovation for emission reduction activities:* Providing credits for purchase of crude from production facilities that have implemented innovative methods, such as CCS, to reduce emissions for crude recovery is consistent with the goal of promoting innovation, at the same time accurately accounting for the reduction in upstream emissions. Apart from providing a market signal for cleaner production, credits generated through such activities can provide extra flexibility for meeting LCFS GHG reduction targets.

   d. *Avoiding or limiting incentives to use crude shuffling to generate credits, avoid deficits, or transfer GHG emissions to other jurisdictions to avoid regulation under the LCFS:* Additionally, a program design that can be exported to other jurisdictions will result in minimizing such GHG emission transfers if other jurisdictions adopt consistent programs.

In addition to meeting the above-mentioned key guiding principles to achieve the intended GHG benefits, amendments to the HCICO provision should be designed so as to avoid incremental adverse environmental and economic impacts. Additionally, considerations for a successful implementation, such as simplicity of methodology, availability of data, and administrative burden, as well as other issues such as fuel supply impacts, etc., should reflect on the decision-making process.

2. Qualitative Evaluation of the Potential Approaches

A qualitative evaluation of each approach with respect to the guiding principles is presented below. It should be noted that the current approach in the regulation, as well as some of the alternatives (Worldwide Average Approach and California Baseline Approach) fall short in many areas when assessed under these principles as explained in the following discussion.

a. *Current Approach with Amendments (Option 1):* The current approach accounts for emissions from crude oil production and transport in the "2006 basket" but does not account for emissions changes over time for crudes that are part of that basket. For example, if emissions associated with the production of California crudes using thermally enhanced oil recovery techniques increases — possible if crude prices remain high and the extraction from the fields become more energy intensive but remains economically viable — this approach would not mitigate those additional GHG emissions. Moreover, a non-baseline crude with a CI of 15 g/MJ or less is counted the same as a crude with a CI of 3 g/MJ. These shortcomings in emissions accounting could result in increased upstream emissions from the use of such crudes. This approach provides an incentive for producers of HCICO to reduce emissions to less than 15 g/MJ. However, the incentive is to avoid the mitigation responsibility that is triggered if HCICO are used; it does not provide a credit that might incent even greater reductions. The current approach limits refiners' flexibility to purchase crude supplies, as they will have significant incentives to avoid using fuels classified as HCICOs. The proposed amendments would assist the industry in identifying crudes that are not HCICOs, increasing their flexibility to use a greater proportion of current crude supplies.

b. *California Average Approach (Option 2):* This approach is the preferred alternative for amendments. It explicitly accounts for and tracks the overall average CI for the transport and production of crudes used by California refineries. The method provides limited incentive for oil companies that produce their own crude oil to reduce emissions (e.g., through flaring reduction or other methods) and promotes innovation. There is likely greater flexibility to purchase worldwide crude supplies than current approach as oil companies have the discretion to shift among crude sources without incurring an incremental deficit, as long as the overall California average CI does not increase. The methodology is simple, providing for a streamlined implementation.

c. *Hybrid California Average/Company Specific Approach (Option 3):* This approach explicitly accounts for all crude used by California refineries and tracks changes over time. It provides greater incentive for oil companies that produce their own crude oil to reduce emissions (e.g., through flaring reduction or other methods) as this will be reflected in their annual CI calculation. There is likely greater flexibility to purchase worldwide crude supplies for some companies than the current approach as oil companies have the discretion to shift among crude sources without incurring an incremental deficit, as long as the overall average CI does not increase. This approach, while providing similar GHG benefits as the California Average Approach, makes implementation more complicated due to the need for company-specific CI values each year. Staff does not have sufficient company-specific data to fully assess the impacts of this approach on individual oil companies.

d. *Company Specific Approach (Option 4):* This approach explicitly accounts for all crude used by California refineries. However, this approach disadvantages those companies that currently refine lower CI crude oil, as their baseline CI value and ability to shift crude supplies would be more limited than those of companies that currently process heavy crudes derived from higher CI production methods. It provides greater incentive for oil companies that produce their own crude oil to reduce emissions (e.g., through flaring reduction or other methods), as this will be reflected in their annual CI calculation. There will be likely greater flexibility to purchase worldwide crude supplies for some oil companies than the current approach, as some companies have the discretion to shift among crude sources without incurring an incremental deficit as long as their overall average CI does not increase. This approach, while providing similar GHG benefits as the California Average Approach, leads to potential uncertainly and confusion in the market due to the need for company-specific compliance schedules. A fuel with the same CI will incur different deficits for different regulated parties under this method. Again, staff does not have sufficient company-specific data to fully assess the impacts of this approach on individual oil companies.

e. *Worldwide Average Approach (Option 5):* This approach has significant drawbacks. It does not explicitly track or account for emissions from crudes used by California refineries. It provides no incentive for oil companies that produce their own oil to reduce emissions (e.g., by reducing flaring) since these reductions will have negligible effect on the worldwide average. There is complete flexibility to purchase worldwide crude supplies, as crudes used by California refineries would have little, if any impacts on the world average. This approach could result in significantly greater amounts of HCICO being used at California refineries because there is no effective incentive to avoid their use. Because it is likely that criteria pollutant emissions increase with greater use of HCICOs — which usually are heavier crudes that typically take additional processing to make clean fuels — this approach could have adverse environmental impacts for the communities located in the vicinity of the refineries.

f. *California Baseline Approach (Option 6):* This approach would eliminate the current HCICO provision, and not replace it with a new approach. It has significant drawbacks. It does not account for, track or mitigate increases in upstream emissions from crudes used by California refineries. This is inconsistent with the LCA basis of the LCFS and undermines the program's goal to achieve a ten percent emission reduction from the 2010 baseline for transportation. It provides no incentive for oil companies that produce their own crude oil to reduce emissions (e.g., by reducing flaring) since these reductions will have no benefit relative to their compliance with the LCFS. There is complete flexibility to purchase worldwide crude supplies, as crudes used by California refineries are not tracked relative to their CIs, and no mitigation would be required if higher crude CIs were to be used. As with the Worldwide Average Approach, this approach could result in significantly greater amounts of harder to refine HCICO being used at California refineries because there is no incentive to avoid their use. Consequently, this approach could have adverse environmental impacts for the communities located in the vicinity of the refineries.

As a result of the above analysis, staff proposes for Board consideration the California Average Approach for the treatment of crude oil under the LCFS. None of the other alternatives considered would be more effective in carrying out the purpose of this high carbon intensity crude oil provision, or would be as effective as, and less burdensome than, the proposed approach.

VIII. SUMMARY AND RATIONALE FOR PROPOSED REGULATIONS

In this chapter, we provide a summary and rationale for each of the affected sections in the regulation:

Section 95480.1. Applicability

Summary of Section 95480.1:

Section 95480.1 specifies which transportation fuels are subject to the LCFS regulation. It also specifies which alternative fuels may generate LCFS credits by electing to opt into the LCFS, and the alternative fuels and specific applications that are exempt from the regulation.

Rationale:

This section is necessary to specifically identify which fuels are subject to the regulation, which fuels are eligible to generate credits by fuel providers opting into the regulation, and which fuels and applications are exempt.

Summary of Subsection 95480.1(b):

This provision specifies the alternative fuels, or “opt-in fuels,” which meet the 2020 carbon intensity standards. The proposed amendment clarifies that an opt-in fuel provider may generate credits only by electing to opt into the LCFS as a regulated party, pursuant to the opt-in and opt-out provisions.

Rationale:

This provision is necessary to identify which fuels are subject to the LCFS regulation and which fuels are exempt. The amendment to this provision is needed to clarify when an alternative fuel provider can generate credits under the opt-in provisions.

Section 95480.2. Persons Eligible for Opting Into the LCFS Program

Purpose of Section 95480.2:

This provision specifies the criteria to be eligible for opting into the LCFS. Staff proposes to add this provision as a new section to the regulation.

Rationale:

This provision is necessary to provide the criteria a person must meet to be eligible for opting into the program. In addition, staff is proposing amendments that would permit out-of-state producers and intermediate entities to be regulated parties. Therefore, these entities are included in this section.

Section 95480.3. Procedure for Opting Into and Opting Out of the LCFS Program

Summary of Section 95480.3:

This section specifies the procedures for opting in and out of the LCFS program. Staff proposes to add opt-in and opt-out procedures, reporting requirements, and selection of CI values.

Rationale:

This section is necessary to specify the procedure and information submittals needed for a fuel provider to opt in or opt out as a regulated party.

Section 95480.4. Multiple Parties Claiming to Be the Regulated Party for the Same Volume of Fuel

Summary of Section 95480.4:

This section establishes the actions taken when more than one party has inadvertently claimed to be the regulated party for the same volume of fuel. Staff proposes to add this as a new section in the regulation.

Rationale:

This section specifies the actions to be taken when more than one party has inadvertently claimed to be the regulated party for the same volume of fuel, including the order credits will be released.

Section 95480.5. Jurisdiction

Summary of Section 95480.5:

This section specifies the actions which establish a person's consent to be subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California.

Rationale:

This section is necessary to implement the enhanced regulated party revisions that would permit out-of-state producers and intermediate entities to voluntarily elect to become regulated parties and, therefore, become subject to California jurisdiction.

Section 95481. Definitions and Acronyms

Summary of Section 95481:

This section provides the specific definitions and acronyms that apply to the regulation. The proposed amendments include revised and new definitions and acronyms.

Rationale:

This section is necessary to specify the definitions and acronyms used in the regulation.

Section 95482. Average Carbon Intensity Requirements for Gasoline and Diesel

Summary of Section 95482:

This section establishes the LCFS compliance schedule from 2011 through 2020 based upon the gasoline and diesel baselines. The proposed amendments revise the compliance schedules for the years 2013 through 2020.

Rationale:

Section 95482 is needed to provide regulated parties with the compliance schedule in which CI requirements are identified. This section is necessary to reflect the proposed revisions to the baseline gasoline and diesel standards, which were first developed in 2006. The intent of the program was to have a 2010 baseline standard and the crude slates have since shifted to require a change in the compliance schedule.

Section 95484. Requirements for Regulated Parties

Summary of Section 95484:

This section establishes the following: 1) criteria by which a regulated party is determined, 2) calculation of credit balance and annual compliance obligation, 3) reporting requirements, 4) recordkeeping and auditing requirements, and 5) violations and penalties. Staff proposes to relocate annual compliance and credit calculation information to the proposed credit trading section 95488.

Rationale:

Section 95484 is needed to provide regulated parties with the requirements and inform them of the penalties for non-compliance. Staff proposes to revise various subsections to implement proposed amendments.

Summary of Section 95484(a):

This subsection establishes the regulated parties for each type of transportation fuel. The proposed amendment revises regulated parties for electricity under section 95484(a)(6).

Rationale:

This section is necessary to provide a clear distinction of which entities can claim title on the credits. This language therefore provides a hierarchy for who may claim the credits and what is required for documentation purposes. The amendment to subsection 95484(a)(6) is needed to identity whom is eligible to claim electricity credits as the regulated party.

Summary of Section 95484(b):

Subsection 95484(b), which is 95484(c) in the existing regulation, provides the reporting requirements for regulated parties. The proposed amendments include mandatory use of the LRT, eliminating the reporting of fuel volume in terms of “gasoline gallon equivalent” (gge), and removal of reporting significant figures to simply report the nearest whole unit.

Rationale:

This subsection is needed to provide regulated parties with the reporting requirements that must be met under LCFS. The proposed amendments to this subsection is necessary to ensure standardization and consistency, which would help facilitate credit trading between regulated parties, and improve how regulated parties are recording their transactions.

Section 95485. LCFS Credits and Deficits

Summary of Section 95485:

This section provides the following information: 1) calculation of credits and deficits, 2) credit generation frequency, 3) credit acquisition, banking, borrowing, and trading, and 4) nature of credits.

Rationale:

Section 95485 is necessary to provide regulated parties with the information needed to calculate the amount of credits and deficits generated, when a regulated party may generate credits, and what a regulated party may or may not do to retain, acquire, transfer, and export credits for compliance.

Summary of Section 95485(a):

This subsection provides regulated parties with the methods that must be used to calculate credits and deficits generated. Staff proposes three changes to the EERs contained in Table 5.

Rationale:

This subsection is needed to provide the calculation methods used to calculated credits and deficits generated. The proposed amendment to the EERs is needed to reflect the use of engine efficiency and fuel efficiency data that was not available during the original rulemaking in 2009.

Section 95486. Determination of Carbon Intensity Values

Summary of Section 95486:

This section provides how CI values for each fuel are determined.

Rationale:

Section 95486 is necessary to provide regulated parties with the information needed to determine the CI values of their fuel.

Summary of Section 95486(a):

Subsection 95486(a) provides the ARB Lookup Table and specifies how a regulated party may select a method and determine CI values. Staff proposes to amend the regulation by adding new subsections 95486(a)(2), (3), and (4).

Subsections 95486(a)(2) and (3) clarifies the procedure by which carbon intensities are determined using the Method 1 process. These new provisions specify that Method 1 can only be used for fuels that are produced using a well-to-wheels production pathway that is substantially similar to the corresponding well-to-wheels pathway described in the pathway document on which an LCFS Lookup Table pathway is based.

Subsection 95486(4) establishes default carbon intensity values.

Rationale:

Subsection 95486(a) is necessary to provide regulated parties the information needed to determine the CI values for each of their fuels or blendstocks. The proposed amendments are needed to clarify the procedure carbon intensities are determined using the Method 1 process, specify that Method 1 can only be used for fuels that are produced using a well-to-wheels production pathway that is substantially similar to the corresponding well-to-wheels pathway from which an LCFS Lookup Table pathway is based, and establish default carbon intensity values.

Summary of Section 95486(b):

Section 95486(b) provides regulated parties the CI lookup table that they may use to select their fuel pathway. The proposed amendment revises how credits are calculated for the incremental credits and deficits associated with high carbon crude oil sources.

Rationale:

This subsection is needed to give regulated parties a location that designates the CI values associated with each fuel pathway. The proposed amendment revises how regulated parties producing gasoline and diesel will handle various crude slates, and the current HCICO provisions have changed from a “bucket method” of crudes to a flexible California average.

Summary of Section 95486(f):

Section 95486(f) provides the requirements for a Method 2A/2B fuel pathway to be processed and approved. The proposed amendment revises how the carbon intensity pathways are evaluated, shifting from a formal rulemaking for each pathway to a certification process.

Rationale:

This subsection is needed to provide the legal support for each pathway that is available for regulated parties to use. The proposed amendment will streamline the process for CI pathways to be incorporated into the regulation by converting the process from an individual rulemaking for each pathway proposed to a certification process. The pathways will then be included into the regulation when the language is revised at a future date.

Section 95488. Banking, Trading, and Purchase of Credits

Summary of Section 95488:

This section provides the following information: 1) calculation of credit balance and annual compliance, 2) generation and acquisition of transferable credits, 3) credit transfers, and 4) mandatory retirement of credits, and 5) public disclosure of credit transfer activity.

Rationale:

Section 95488 is needed as the current regulatory text allows for the transfers of credits, but is silent in the procedure. The proposed language will provide regulated parties with the calculation on how credits are to be banked, the requirements and information that ARB will need to process a credit transfer, the information ARB will need to retire credits at the end of the annual compliance period, and the information that will be disclosed to the public relaying market activity and overall health of the LCFS program.

<u>Summary of Section 95488(a):</u>

Section 95488(a) was relocated from section 95484(b) in the existing regulation. The proposed amendments will provide a clear separation of credit generation and tracking from deficit accounting and provide a revised calculation for annual compliance.

<u>Rationale:</u>

This section is needed to provide regulated parties the definitions and calculations that will be used to determine compliance. The proposed amendments will clearly delineate between credit and deficit generation during the annual compliance period and remove the concept of "net" credit balance upon submission of a quarterly report.

<u>Summary of Section 95488(b):</u>

Section 95488(b) provides a regulated party the procedure on how a credit is generated and validated before it becomes available for trade. It also defines the time that a credit can be purchased after the annual compliance period has ended prior to the submittal of the annual compliance report.

<u>Rationale:</u>

This subsection is needed as the existing regulation is silent on when a credit is available for transfer and to clarify when a regulated party may purchase credits to meet their annual compliance obligation.

<u>Summary of Section 95488(c)</u>

Section 95488(c) provides the requirements that are required by ARB before a credit can be transferred and the associated documentation to confirm the transfer has occurred.

<u>Rationale:</u>

This subsection is needed for ARB to process and confirm trades between regulated parties.

<u>Summary of Section 95488(d):</u>

Section 95488(d) provides a procedure to regulated parties on how their credits at the end of each annual compliance period may be retired.

Rationale:

This subsection is needed if the use of unique IDs is implemented in the reporting tool. Regulated parties will be able to select the credits they wish to retire or allow the default order to be used offset their deficits.

Summary of Section 95488(e):

Section 95488(e) provides a description on the information the public will receive on a monthly basis. The information will include credit and deficit generation by the LCFS program as well as credit market activity.

Rationale:

This subsection is needed as the regulation requires a certain level of transparency. The public and market participants will therefore receive routine, periodic releases of information on credit and deficit generation as well as trading activity to allow the public an overview of LCFS progress.

IX. REFERENCES AND FOOTNOTES

Note: The references are listed according to the footnote they correspond to in the ISOR. Not all footnotes are references and are only listed here to maintain the numbering system used for the ISOR footnotes. The footnotes that are not references are listed as "Explanatory Footnote."

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APPENDIX A

PROPOSED REGULATION ORDER

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PROPOSED REGULATION ORDER

Amend sections 95480.1, 95481, 95484, 95485, 95486, 95488, and 95490, title 17, California Code of Regulations (CCR), to read as follows:

Adopt new sections 95480.2, 95480.3, 95480.4, and 95480.5, title 17, CCR, to read as follows:

[**Note:** The original regulatory text is show in plain type. The proposed amendments are shown in underline to indicate addition and strikeout to show deletions. All other portions remain unchanged and are indicated by the symbol "* * * * *" for reference]

Subchapter 10. Climate Change
Article 4. Regulations to Achieve Greenhouse Gas Emission Reductions

Subarticle 7. Low Carbon Fuel Standard

Section 95480. Purpose.

* * * * *

Section 95480.1. Applicability.

(a) *Applicability of the Low Carbon Fuel Standard.*

Except as provided in this section, the California Low Carbon Fuel Standard regulation, title 17, California Code of Regulations (CCR), sections 95480 through 95490 (collectively referred to as the "LCFS") applies to any transportation fuel, as defined in section 95481, that is sold, supplied, or offered for sale in California, and to any person who, as a regulated party defined in section 95481 and specified in section 95484(a), is responsible for a transportation fuel in a calendar year. The types of transportation fuels to which the LCFS applies include:

(1) California reformulated gasoline ("gasoline" or "CaRFG");
(2) California diesel fuel ("diesel fuel" or "ULSD");
(3) Fossil compressed natural gas ("Fossil CNG") or fossil liquefied natural gas ("Fossil LNG");
(4) Biogas CNG or biogas LNG;
(5) Electricity;
(6) Compressed or liquefied hydrogen ("hydrogen");
(7) A fuel blend containing hydrogen ("hydrogen blend");
(8) A fuel blend containing greater than 10 percent ethanol by volume;
(9) A fuel blend containing biomass-based diesel;
(10) Denatured fuel ethanol ("E100");

(11) Neat biomass-based diesel ("B100"); and
(12) Any other liquid or non-liquid fuel.

The provisions and requirements in section 95484(b~~c~~), (c~~d~~) and (b~~e~~) apply starting January 1, 2010. All other provisions and requirements of the LCFS regulation apply starting January 1, 2011.

(b) *Credit Generation Opt-In Provision for Specific Alternative Fuels.* Each of the following alternative fuels ("opt-in fuels") is presumed to have a full fuel-cycle, carbon intensity that meets the compliance schedules set forth in section 95482(b) and (c) through December 31, 2020. A fuel provider for an alternative fuel listed below may generate LCFS credits for that fuel only by electing to opt into the LCFS as a regulated party pursuant to section 95480.3 and meeting the requirements of this regulation: ~~With regard to an alternative fuel listed below, the regulated party for the fuel must meet the requirements of the LCFS regulation only if the regulated party elects to generate LCFS credits:~~

(1) Electricity;
(2) Hydrogen;
(3) A hydrogen blend;
(4) Fossil CNG derived from North American sources;
(5) Biogas CNG; and
(6) Biogas LNG.

(c) *Exemption for Specific Alternative Fuels.* The LCFS regulation does not apply to an alternative fuel that meets the criteria in either (c)(1) or (2) below:

(1) An alternative fuel that:

(A) is not a biomass-based fuel; and
(B) is supplied in California by all providers of that particular fuel for transportation use at an aggregated volume of less than 420 million MJ (3.6 million gasoline gallon equivalent) per year;

A regulated party that believes it is subject to this exemption has the sole burden of proving to the Executive Officer's satisfaction that the exemption applies to the regulated party.

(2) Liquefied petroleum gas (LPG or "propane").

(d) *Exemption for Specific Applications.* The LCFS regulation does not apply to any transportation fuel used in the following applications:

(1) Aircraft;
(2) Racing vehicles, as defined in H&S section 39048;
(3) Military tactical vehicles and tactical support equipment, as defined in

title 13, CCR, section 1905(a) and title 17, CCR, section 93116.2(a)(36), respectively;

(4) Locomotives not subject to the requirements specified in title 17, CCR, section 93117; and

(5) Ocean-going vessels, as defined in title 17, CCR, section 93118.5(d). This exemption does not apply to recreational and commercial harbor craft, as defined in title 17, CCR, section 93118.5(d).

(e) Nothing in this LCFS regulation (title 17, CCR, § 95480 et seq.) may be construed to amend, repeal, modify, or change in any way the California reformulated gasoline regulations (CaRFG, title 13, CCR, § 2260 et seq.), the California diesel fuel regulations (title 13, CCR, §§ 2281-2285 and title 17, CCR, § 93114), or any other applicable State or federal requirements. A person, including but not limited to the regulated party as that term is defined in the LCFS regulation, who is subject to the LCFS regulation or other State and federal regulations shall be solely responsible for ensuring compliance with all applicable LCFS requirements and other State and federal requirements, including but not limited to the CaRFG requirements and obtaining any necessary approvals, exemptions, or orders from either the State or federal government.

(f) *Severability*. Each part of this subarticle shall be deemed severable, and in the event that any part of this subarticle is held to be invalid, the remainder of this subarticle shall continue in full force and effect.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

<u>Section 95480.2. Persons Eligible for Opting Into the LCFS Program.</u>

<u>Only a person who meets one or more of the following criteria can elect to opt into the LCFS program, thereby becoming the regulated party in the LCFS program for a specified volume of fuel ("opt in" and "opt into" include the past, present, and future tenses):</u>

<u>(a) A person who provides a fuel specified in section 95480.1(b) and meets the requirements of section 95484(a)(5), (a)(6), or (a)(7), whichever applies to that fuel;</u>

<u>(b) An out-of-state producer of oxygenate for blending with CARBOB or gasoline, or biomass-based diesel for blending with CARB diesel, who is not otherwise already subject to the LCFS regulation as an importer. An opt-in regulated party</u>

under this subsection may retain the compliance obligation, for a specific volume of fuel or blendstock, only if that person sells the fuel to another regulated party.

(c) A person who is in the distribution/marketing chain of imported fuel and is positioned on that chain between the producer under (b) and the importer ("intermediate entity"). The intermediate entity is subject to the following requirements:

(1) The intermediate entity must provide written documentation demonstrating all the following requirements to the Executive Officer's written satisfaction before opting into the LCFS:

(A) The person received ownership of the fuel for which the person is claiming to generate LCFS credits;

(B) Either:

1. The person received the LCFS compliance obligation from a producer that opted in under section 95480.2(b); or
2. The producer did not opt in under section 95480.2(b).

(C) The person actually delivered the fuel or caused the fuel to be delivered to California;

(D) The fuel delivered under (C) is shown to have been sold for use in California or was otherwise actually used in California; and

(E) The person is not otherwise already subject to the LCFS regulation as a regulated party.

(2) The demonstrations in (1)(A) through (E) above must be made for the specific volume of fuel upon which the person first elects to opt into the LCFS. For subsequent volumes of fuel for which the person is claiming to be the regulated party pursuant to this subsection (c), the person must retain documentation to support the demonstrations required in (1)(A) through (E) and must submit such documentation to the Executive Officer within 30 [working/business?] days upon request.

(d) The gas company, utility, or energy service provider that supplies natural gas ("natural gas supplier") to a person that falls within the provisions of section 95484(a)(5)(A)1.a or (5)(A)2. The natural gas supplier must provide written documentation to the Executive Officer demonstrating all the following before opting in to the LCFS:

(1) The person who falls within the provisions of section 95484(a)(5)(A)1.a. or (5)(A)2. understands that it has the ability to opt into the LCFS program as a regulated party under section 95480.2(a);

(2) The person in (1) has affirmatively elected not to become a regulated party in the LCFS program;

(3) The person in (1) understands and agrees that the election in (2) is irrevocable unless otherwise specified in a written contract between that person and the natural gas supplier; and

(4) As a consequence of the election in (2), the person in (1) understands and agrees that all LCFS credits generated from the sale of CNG dispensed through that person's natural gas vehicle fueling equipment shall belong to the natural gas supplier, unless otherwise specified in a written contract between the person and the natural gas supplier.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95480.3. Procedure for Opting Into and Opting Out of the LCFS Program.

Opting into and opting out of the LCFS program is available only to a person that is eligible under section 95480.2. The procedure for opting into and opting out of the LCFS for such a person is set forth as follows.

(a) *Opting In*.

(1) Opting into the LCFS program becomes effective when the fuel provider registers, pursuant to this section, as a regulated party in the LCFS Reporting Tool (LRT), which is available at: https://ssl.arb.ca.gov/lcfsrt/Login.aspx.

(2) Registration under subsection (a)(1) above as a regulated party means that the fuel provider understands the requirements of the LCFS regulation and has agreed to be subject to all the requirements and provisions of the LCFS regulation as a regulated party, pursuant to section 95480.5, in exchange for gaining the ability to generate and trade LCFS credits.

(b) *Selection of Carbon Intensity Value.*

As part of its registration, the regulated party of a fuel listed in subsection 95480.1(b)(1)(A)-(F) must elect for each of its opt-in fuels a carbon intensity (CI) value using one of the following methods:

(1) Method 1, pursuant to section 95486(a) and (b), if an applicable fuel pathway and CI value exist in the Lookup Table in section 95486(b) at the time of selection;

(2) Method 2A or 2B, pursuant to section 95486(c)-(f); or

(3) In lieu of (1) or (2) above, the regulated party may choose the CI value of 87.65 g CO2e/MJ when the opt-in fuel is used as a gasoline substitute or 86.72 g CO2e/MJ when the fuel is used as a diesel substitute. This is because the opt-in fuels listed in section 95480.1(b) have been deemed to have a full fuel lifecycle CI that meets the regulation's 2020 standards, as specified in section 95482(b) and (c). A regulated party choosing a CI value pursuant to this paragraph (3) must use an energy economy ratio (EER) in its LRT quarterly and annual reports that is set to a value of 1.0. Selection of a CI value pursuant to this paragraph does not preclude an opted-in regulated party from pursuing approval of a Method 2A or 2B application at the same or later time, nor does it preclude the regulated party from using Method 1 when an applicable fuel pathway and CI value are incorporated into the Lookup Table or are posted by the Executive Officer at: http://www.arb.ca.gov/fuels/lcfs/2a2b/2a-2b-apps.htm.

(c) *Opting Out.*

A fuel provider, who elected to become a regulated party by opting into the LCFS pursuant to subsection (a) above, may decide later to return to exempt status under section 95480.1(b)(1) ("opt out"). For an election to opt out of the LCFS regulation to be effective, the regulated party must complete all actions specified below, with the completed actions documented in writing and submitted to ARB as specified below:

(1) *90 Days before Opt-Out Date*.

(A) Provide ARB with a 90-day written notice of intent to opt out and the anticipated opt-out effective date;

(B) Using the LRT, provide ARB with any outstanding quarterly progress report (for the quarter in which the opt-out will occur) and annual compliance report (covering January 1st of the year to the date of the opt-out notice); and

(C) Identify in the 90-day notice any actions to be taken to eliminate any remaining deficits by the opt-out date.

(2) *Effective Opt-Out Date.*

Eliminate all remaining deficits and provide verification by email or regular mail that opt out occurred and all deficits have been eliminated. The Executive Office shall confirm receipt of the notification within 3 business days. Any credits that remain in the regulated party's account at the time of the opt out shall be forfeited to the State.

(3) *30 Days after Opt-Out Date.*

(A) Identify in writing the amount and transferee (if applicable) of any LCFS credits generated between the 30-day notice and the date of opt-out;

(B) Verify in writing that the former regulated party's deficit balance is zero as of the date of opt out. The verification must be signed by an authorized company representative, who must attest that the company will not sell, trade, or otherwise transact any LCFS credits after the opt-out date;

(C) Update the quarterly and annual compliance reports submitted with the 30-day notice, as needed, to reflect any changes that occurred during the period between the notice and the actual opt-out date.

(4) *December 31st of the Year of Opt Out and the Following Year.*

Confirm in writing that the former regulated party remains opted out of the LCFS program and has not sold, traded, or otherwise transacted any LCFS credits since opt-out date.

(5) *Written Submittals.*

All notifications, identifications, and other documentation specified in this section 95480.3 must be submitted to:

Chief, Alternative Fuels Branch
California Air Resources Board
1001 I Street, P.O. Box 2815
Sacramento, CA 95812-2815; or

The LRT Administrator: lrtadmin@arb.ca.gov.

(d) *Recordkeeping Requirements.*

The provisions and requirements in section 95484(c)(1) shall apply to a regulated party that has opted out of the LCFS regulation.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95480.4. Multiple Parties Claiming to Be the Regulated Party for the Same Volume of Fuel.

There can only be one regulated party for a specific volume of fuel at any given time. In the event that more than one person has registered with ARB as the regulated party for the same volume of fuel, the following provisions shall apply:

(a) All LCFS credits generated from the volume of fuel at issue shall be made inaccessible to the regulated parties and placed by the Executive Officer into a holding account, including any such credits that have already been transferred to another person prior to being notified by the Executive Officer that the holding action has taken place;

(b) The regulated parties for a credit placed in a holding account pursuant to (a) shall not sell, offer for sale, trade, or otherwise transfer such a credit to another person until the holding action has been lifted by the Executive Officer;

(c) The Executive Officer shall lift the hold on a LCFS credit within 30 working days after initially placing the hold, and shall release the credit to a regulated party based on the following procedure in descending order of priority:

(1) The producer that has opted in under section 95480.2(b) and retained the compliance obligation; if this provision does not apply, then

(2) The intermediate entity (downstream of the producer) that has opted in under section 95480.2(c) and retained the compliance obligation; if this provision does not apply, then

(3) The importer, if neither (1) nor (2) applies, which has retained the compliance obligation pursuant to section 95484; if this provision does not apply, then

(4) The regulated party that received compliance obligation from the importer in (3) or a California producer pursuant to section 95484.

Paragraphs (c)(1), (2), (3), and (4) above notwithstanding, the parties above may, by the time ownership to the fuel or blendstock is transferred, specify by enforceable written contract pursuant to section 95484 the person to which the credits ultimately have been transferred and obligated.

(d) It is a violation of this regulation for a person to register as the regulated party for a specific volume of fuel if doing so would be unreasonable under the circumstances.

(e) This section does not apply to regulated parties for electricity, which are subject to the provisions of section 95484(a)(6).

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95480.5. Jurisdiction.

(a) Any of the following actions shall conclusively establish a person's consent to be subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California:

(1) Registration with ARB as a regulated party pursuant to the opt-in provisions in section 95480.3(a); or

(2) Receipt of compensation of any kind, including sales proceeds and commissions, from any transfers of a LCFS credit made pursuant to section 95488.

(b) Any person who, pursuant to section 95484(a)(1) through (4), inclusive, is the initial regulated party or a person to whom the compliance obligation has been transferred directly or indirectly from the initial regulated party, is subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California, irrespective of whether the person has registered as a regulated party in the LRT.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95481. Definitions and Acronyms.

(a) *Definitions.* For the purposes of sections 95480 through 95489, the definitions in Health and Safety Code sections 39010 through 39060 shall apply, except as otherwise specified in this section, section 95480.1, sections 95480.2 through 95480.5, or sections 95482 through 95489:

(1) "Aggregation Indicator" means an identifier in the LCFS Reporting Tool (LRT) for reported transactions that are a result of an aggregation or summing of more than one transaction. An entry of 'True' indicates that multiple transactions have been aggregated and are reported with a single Transaction Number. An entry of 'False' means that the transaction record results from one physical transaction reported as a single Transaction Number.

(~~1~~2) "Alternative fuel" means any transportation fuel that is not CaRFG or a diesel fuel, including but not limited to, those fuels specified in section 95480.1(a)(3) through (a)(12).

(3) "Application" means the type of vehicle where the fuel is consumed in terms of LDV/MDV for light duty vehicle / medium duty vehicle or HDV for heavy-duty vehicle.

(~~2~~4) "B100" means biodiesel meeting ASTM D6751-08 (October 1, 2008) (*Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels*), which is incorporated herein by reference.

(~~3~~5) "Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel meeting all the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR part 79;
(B) A mono-alkyl ester;
(C) Meets ASTM D 6751-08 (October 1, 2008), *Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels,* which is incorporated herein by reference;
(D) Intended for use in engines that are designed to run on conventional diesel fuel; and
(E) Derived from nonpetroleum renewable resources.

(~~4~~6) "Biodiesel Blend" means a blend of biodiesel and diesel fuel containing 6% (B6) to 20% (B20) biodiesel and meeting ASTM D7467-08

(October 1, 2008), *Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to 20)*, which is incorporated herein by reference.

(7) “Biofuel Production Facility” means an identifier in the LRT that refers to the production facility in which the biofuel was produced.

(~~5~~8) “Biogas (also called biomethane) means natural gas that ~~meets the requirements of 13 CCR §2292.5 and~~ is produced from the breakdown of organic material in the absence of oxygen. Biogas is produced in processes including, but not limited to, anaerobic digestion, anaerobic decomposition, and thermo-chemical decomposition. These processes are applied to biodegradable biomass materials, such as manure, sewage, municipal solid waste, green waste, and waste from energy crops, to produce landfill gas, digester gas, and other forms of biogas.

(~~6~~9) “Biogas CNG” means CNG consisting solely of compressed biogas.

(~~7~~10) “Biogas LNG” means LNG consisting solely of liquefied biogas.

(~~8~~11) "Biomass" has the same meaning as defined in "Renewable Energy Program: Overall Program Guidebook," 2nd Ed., California Energy Commission, Report No. CEC-300-2007-003-ED2-CMF, January 2008, which is incorporated herein by reference.

(~~9~~12) “Biomass-based diesel” means a biodiesel (mono-alkyl ester) or a renewable diesel that complies with ASTM D975-08ae1, (edited December 2008), *Specification for Diesel Fuel Oils*, which is incorporated herein by reference. This includes a renewable fuel derived from co-processing biomass with a petroleum feedstock.

(~~10~~13) “Blendstock” means a component that is either used alone or is blended with another component(s) to produce a finished fuel used in a motor vehicle. Each blendstock corresponds to a fuel pathway in the California-modified GREET. A blendstock that is used directly as a transportation fuel in a vehicle is considered a finished fuel.

(14) “Business Partner” means the identifier in the LRT that refers to the counter party in a specific transaction involving the regulated party. This can either be the buyer or seller of fuel, whichever applies to the specific transaction.

(~~11~~15) “Carbon intensity” means the amount of lifecycle greenhouse gas emissions, per unit of energy of fuel delivered, expressed in grams of carbon dioxide equivalent per megajoule (gCO2E/MJ).

(~~12~~16) "Compressed Natural Gas (CNG)" means natural gas that has been compressed to a pressure greater than ambient pressure~~ and meets the requirements of title 13, CCR, section 2292.5~~.

(~~13~~17) "Credits" and "deficits" means the measures used for determining a regulated party's compliance with the average carbon intensity requirements in sections 95482 and 95483. Credits and deficits are denominated in units of metric tons of carbon dioxide equivalent (CO2E), and are calculated pursuant to section 95485(a).

(~~14~~18) "Diesel Fuel" (also called conventional diesel fuel) has the same meaning as specified in title 13, CCR, section 2281(b).

(~~15~~19) "Diesel Fuel Blend" means a blend of diesel fuel and biodiesel containing no more than 5% (B5) biodiesel by weight and meeting ASTM D975-08ae1, (edited December 2008), *Specification for Diesel Fuel Oils*, which is incorporated herein by reference.

(~~16~~20) "E100," also known as "Denatured Fuel Ethanol," means nominally anhydrous ethyl alcohol meeting ASTM D4806-08 (July 1, 2008), *Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel*, which is incorporated herein by reference.

(~~17~~21) "Executive Officer" means the Executive Officer of the Air Resources Board, or his or her designee.

(22) "Electrical Distribution Utility" means an entity that owns or operates an electrical distribution system, including:

(A) a public utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU); or
(B) a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3; or
(C) an Electrical Cooperative (COOP) as defined in Public Utilities Code section 2776

which provides electricity to retail end users in California.

(~~18~~23) "Final Distribution Facility" means the stationary finished fuel transfer point from which the finished fuel is transferred into the cargo tank truck, pipeline, or other delivery vessel for delivery to the facility at which the finished fuel will be dispensed into motor vehicles.

(~~19~~24) "Finished fuel" means a fuel that is used directly in a vehicle for transportation purposes without requiring additional chemical or physical processing.

(~~20~~25) "Fossil CNG" means CNG that is derived solely from petroleum or fossil sources, such as oil fields and coal beds.

(26) "Fuel Pathway Code" means the identifier in the LRT that applies to a specific fuel pathway in the Lookup Table, as determined pursuant to section 95486(a)(2).

(~~20.5~~27) "GTAP" or "GTAP Model" means the Global Trade Analysis Project Model (January 2010), which is hereby incorporated by reference, and is a software package comprised of:

(A) RunGTAP (February 2009), a visual interface for use with the GTAP databases (posted at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm in February 2009 and available for download at https://www.gtap.agecon.purdue.edu/products/rungtap/default.asp), which is hereby incorporated by reference;

(B) GTAP-BIO (February 2009), the GTAP model customized for corn ethanol (posted at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm in February 2009 and available with its components as a .zip file for download at http://www.arb.ca.gov/fuels/lcfs/gtapbio.zip); which is hereby incorporated by reference;

(C) GTP-SGR (February 2009), the GTAP model customized for sugarcane ethanol (posted at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm in February 2009 and available with its components as a .zip file for download at http://www.arb.ca.gov/fuels/lcfs/gtpsgr.zip), which is hereby incorporated by reference; and

(D) GTAP-SOY (January 2010), the compressed file containing the GTAP model customized for Midwest soybeans (posted at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm in January 2010 and available with its components as a .zip file for download at http://www.arb.ca.gov/fuels/lcfs/gtap-soy.zip), which is hereby incorporated by reference.

(~~21~~28) "HDV" means a heavy-duty vehicle that is rated at 14,001 or more pounds gross vehicle weight rating (GVWR).

(~~22~~29) "Home fueling" means the dispensing of fuel by use of a fueling appliance that is located on or within a residential property with access limited to a single household.

(~~23~~30) "Import" means to bring a product from outside California into California.

(~~24~~31) "Importer" means the person who owns the liquid transportation fuel or blendstock, in the transportation equipment that held or carried the product, at the point the equipment entered California. For purposes of this definition, "transportation equipment" includes, but is not limited to, rail cars, cargo tanker trucks, and pipelines. ~~an imported product when it is received at the import facility in California.~~

~~(25) "Import facility" means, with respect to any imported liquid product, the storage tank in which the product was first delivered from outside California into California, including, in the case of liquid product imported by cargo tank and delivered directly to a facility for dispensing the product into motor vehicles, the cargo tank in which the product was imported.~~

(~~26~~32) "Intermediate calculated value" means a value that is used in the calculation of a reported value but does not by itself meet the reporting requirement under section 95484(b~~c~~).

(~~27~~33) "LDV & MDV" means a vehicle category that includes both light-duty (LDV) and medium-duty vehicles (MDV).

(A) "LDV" means a vehicle that is rated at 8500 pounds or less GVWR.
(B) "MDV" means a vehicle that is rated between 8501 and 14,000 pounds GVWR.

(~~28~~34) "Lifecycle greenhouse gas emissions" means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Executive Officer, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.

(~~29~~35) "Liquefied Natural Gas (LNG)" means natural gas that has been liquefied ~~and meets the requirements of title 13, CCR, section 2292.5~~.

(~~30~~36) "Liquefied petroleum gas (LPG or propane)" has the same meaning as defined in Vehicle Code section 380.

(37) “LRT Reporting Deadlines” means the five reporting dates specified in section 95484(b)(1).

(~~31~~38) “Motor vehicle” has the same meaning as defined in section 415 of the Vehicle Code.

(~~32~~39) “Multi-fuel vehicle” means a vehicle that uses two or more distinct fuels for its operation. A multi-fuel vehicle (also called a vehicle operating in blended-mode) includes a bi-fuel vehicle and can have two or more fueling ports onboard the vehicle. A fueling port can be an electrical plug or a receptacle for liquid or gaseous fuel. As an example, a plug-in hybrid hydrogen internal combustion engine vehicle (ICEV) uses both electricity and hydrogen as the fuel source and can be “refueled” using two separately distinct fueling ports.

(~~33~~40) “Multimedia evaluation” has the same meaning as specified in H&S section 43830.8(b) and (c).

(~~34~~41) “Natural gas” means a mixture of gaseous hydrocarbons and other compounds, with at least 80 percent methane (by volume), and typically sold or distributed by utilities, such as any utility company regulated by the California Public Utilities Commission.

(42) “Petroleum Intermediate” means a petroleum product that can be further processed to produce CARBOB, diesel, or other petroleum blendstocks.

(43) “Physical Pathway Code (PPC)” means the code in the LRT that describes the applicable physical pathway, as defined in section 95484(c)(2).

(~~35~~44) “Private access fueling facility” means a fueling facility with access restricted to privately-distributed electronic cards (“cardlock”) or is located in a secure area not accessible to the public.

(~~36~~45) “Producer” means, with respect to any liquid fuel, the person who owns the liquid fuel when it is supplied from the production facility. “Producer” includes an “out-of-state producer,” which is a producer that has its production facility located outside California.

(~~37~~46) “Production facility” means, with respect to any liquid fuel (other than LNG), a facility in California at which the fuel is produced. For an “out-of-state producer,” the production facility is located outside California. "Production facility" means, with respect to natural gas (CNG, LNG or biogas), a facility in California at which fuel is converted, compressed, liquefied, refined, treated, or otherwise processed into CNG, LNG, biogas, or biogas-natural gas blend that is ready for transportation use in a vehicle without further physical or chemical processing.

(~~38~~47) "Public access fueling facility" means a fueling facility that is not a private access fueling dispenser.

(~~39~~48) "Regulated party" means a person who, pursuant to section 95484(a), must meet the average carbon intensity requirements in section 95482 or 95483.

(~~40~~49) "Renewable diesel" means a motor vehicle fuel or fuel additive that is all the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR part 79;
(B) Not a mono-alkyl ester;
(C) Intended for use in engines that are designed to run on conventional diesel fuel; and
(D) Derived from nonpetroleum renewable resources.

(~~41~~50) "Single fuel vehicle" means a vehicle that uses a single external source of fuel for its operation. The fuel can be a pure fuel, such as gasoline, or a blended fuel such as E85 or a diesel fuel containing biomass-based diesel. ~~A dedicated fuel vehicle has one fueling port onboard the vehicle. Examples include BEV, E85 FFV, vehicles running on a biomass-based diesel blend, and grid-independent hybrids such as a Toyota Prius.®~~

(51) "Transaction Date" means the identifier in the LRT that specifies the title transfer date as shown on the Product Transfer Document.

(52) "Transaction Quantity" means the identifier in the LRT that specifies the amount of fuel reported in a transaction. A Transaction Quantity may be reported in gallons, KWh, scf, or other appropriate units.

(53) "Transaction Type" means the identifier in the LRT that describes the nature of a fuel-based transaction, as defined below:

(A) "Production" means the transportation fuel was produced inside California;
(B) "Import" means the transportation fuel was produced outside California and imported into California;
(C) "Purchased with Obligation" means the transportation fuel was purchased with the compliance obligation from a regulated party;
(D) "Purchased without Obligation" means the transportation fuel was purchased without the compliance obligation from a regulated party;
(E) "Sold with Obligation" means the transportation fuel was sold with the compliance obligation by a regulated party;

(F) “Sold without Obligation” means the transportation fuel was sold without the compliance obligation by a regulated party;
(G) “Export” means the transportation fuel was exported outside of California after temporarily being in California;
(H) “Loss of Inventory” means the fuel entered the California fuel pool but was not used in a motor vehicle due to spillage; and
(I) “Not Used for Transportation” means the fuel did not meet the definition specified in section 95481(a)(52).

(~~42~~54) “Transportation fuel” means any fuel used or intended for use as a motor vehicle fuel or for transportation purposes in a nonvehicular source.

(b) *Acronyms.* For the purposes of sections 95480 through 95489, the following acronyms apply.

(1) “ASTM” means ASTM International (formerly American Society for Testing and Materials).
(2) “BEV” means battery electric vehicles.
(3) “CARBOB” means California reformulated gasoline blendstock for oxygenate blending
(4) “CaRFG” means California reformulated gasoline.
(5) “CEC” means California Energy Commission.
(6) “CFR” means code of federal regulations.
(7) “CI” means carbon intensity.
(8) “CNG” means compressed natural gas.
(9) “EER” means energy economy ratio.
(10) “FCV” means fuel cell vehicles.
(11) “FFV” means flex fuel vehicles.
(12) “gCO2E/MJ” means grams of carbon dioxide equivalent per mega joule.
(13) “GREET” means the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model.
(14) “GVWR” means gross vehicle weight rating.
(15) “HDV” means heavy-duty vehicles.
(16) “ICEV” means internal combustion engine vehicle.
(17) “LCFS” means Low Carbon Fuel Standard.
(18) “LDV” means light-duty vehicles.
(19) “LNG” means liquefied natural gas.
(20) “LPG” means liquefied petroleum gas.
(21) “LRT” means LCFS reporting tool.
(22) “MCON” means marketable crude oil name.
(~~21~~23) “MDV” means medium-duty vehicles.
(~~22~~24) “MT” means metric tons of carbon dioxide equivalent.
(~~23~~25) “PHEV” means plug-in hybrid vehicles.
(26) “TEOR” means thermally enhanced oil recovery.
(~~24~~27) “ULSD” means California ultra low sulfur diesel.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95482. Average Carbon Intensity Requirements for Gasoline and Diesel.

(a) Starting January 1, 2011 and for each year thereafter, a regulated party must meet the average carbon intensity requirements set forth in Table 1 and Table 2 of this section for its transportation gasoline and diesel fuel, respectively, in each calendar year. For 2010 only, a regulated party does not need to meet a carbon intensity requirement, but it must meet the reporting requirements set forth in section 95484(b~~c~~).

(b) *Requirements for gasoline and fuels used as a substitute for gasoline*.

*Table 1. LCFS Compliance Schedule for 2011 to 2020 for Gasoline and Fuels Used as a Substitute for Gasoline.**

Year	Average Carbon Intensity (gCO2E/MJ)	~~% Reduction~~
2010	Reporting Only	
2011	95.61	~~0.25%~~
2012	95.37	~~0.5%~~
2013	96.42 ~~94.89~~	~~1.0%~~
2014	95.93 ~~94.41~~	~~1.5%~~
2015	94.95 ~~93.45~~	~~2.5%~~
2016	93.98 ~~92.50~~	~~3.5%~~
2017	92.52 ~~91.06~~	~~5.0%~~
2018	91.06 ~~89.62~~	~~6.5%~~
2019	89.60 ~~88.18~~	~~8.0%~~
2020 and subsequent years	87.65 ~~86.27~~	~~10.0%~~

* The average carbon intensity requirements for years 2011 and 2012 reflect reductions from base year (2010) CI values for CaRFG calculated using the CI for crude oil used in California refineries in 2006. The average carbon intensity requirements for years 2013 to 2020 reflect reductions from revised base year (2010) CI values for CaRFG calculated using the CI for crude oil used in California refineries in 2009.

(c) *Requirements for diesel fuel and fuels used as a substitute for diesel fuel.*

*Table 2. LCFS Compliance Schedule for 2011 to 2020 for Diesel Fuel and Fuels Used as a Substitute for Diesel Fuel.***

Year	Average Carbon Intensity (gCO2E/MJ)	~~% Reduction~~
2010	Reporting Only	
2011	94.47	~~0.25%~~
2012	94.24	~~0.5%~~
2013	95.40 ~~93.76~~	~~1.0%~~
2014	94.91 ~~93.29~~	~~1.5%~~
2015	93.95 ~~92.34~~	~~2.5%~~
2016	92.99 ~~91.40~~	~~3.5%~~
2017	91.54 ~~89.97~~	~~5.0%~~
2018	90.10 ~~88.55~~	~~6.5%~~
2019	88.65 ~~87.13~~	~~8.0%~~
2020 and subsequent years	86.72 ~~85.24~~	~~10.0%~~

** The average carbon intensity requirements for years 2011 and 2012 reflect reductions from base year (2010) CI values for ULSD calculated using the CI for crude oil used in California refineries in 2006. The average carbon intensity requirements for years 2013 to 2020 reflect reductions from revised base year (2010) CI values for ULSD calculated using the CI for crude oil used in California refineries in 2009.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95483. Average Carbon Intensity Requirements for Alternative Fuels.

* * * * *

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95484. Requirements for Regulated Parties.

(a) *Identification of Regulated Parties.* The purpose of this part is to establish the criteria by which a regulated party is determined. The regulated party is initially established for each type of transportation fuel, but this part provides for the transfer of regulated party status and the associated compliance obligations by agreement, notification, or other means, as specified below.

(1) *Regulated Parties for Gasoline*.

(A) *Designation of Producers and Importers as Regulated Parties*.

1. *Where Oxygenate Is Added to Downstream CARBOB.*

For gasoline consisting of CARBOB and an oxygenate added downstream from the California facility at which the CARBOB was produced or imported, the regulated party is initially the following:

a. With respect to the CARBOB, the regulated party is the producer or importer of the CARBOB; and

b. With respect to the oxygenate, the regulated party is the producer or importer of the oxygenate.

2. *Where No Separate CARBOB*. For gasoline that does not include CARBOB that had previously been supplied from the facility at which was produced or imported, the regulated party for the gasoline is the producer or importer of the gasoline.

(B) *Effect of Transfer of CARBOB by Regulated Party.*

1. *Threshold Determination Whether Recipient of CARBOB is a Producer or Importer.* Whenever a person who is the regulated party for CARBOB transfers ownership of the CARBOB, the recipient must notify the transferor whether the recipient is a producer or importer for purposes of this section 95484(a)(1)(B).

2. *Producer or Importer Acquiring CARBOB Becomes the Regulated Party Unless Specified Conditions Are Met.* Except as provided for in section 95484(a)(1)(B)3., when a person who is the regulated party transfers ownership of the CARBOB to a producer or importer, the recipient of ownership of the CARBOB (i.e., the transferee) becomes the

regulated party for it. The transferor must provide the recipient a product transfer document that prominently states the information specified in paragraphs a. and b. below, and the transferor and recipient must meet the requirements specified in paragraph c., as set forth below:

a. the volume and average carbon intensity of the transferred CARBOB. ~~For a transferor that is a regulated party subject to section 95486(b)(2)(A)2., the~~ The transferor of CARBOB may report as the "average carbon intensity" on the product transfer document the total carbon intensity value for CARBOB as shown in the Carbon Intensity Lookup Table; and

b. the recipient is now the regulated party for the acquired CARBOB and accordingly is responsible for meeting the requirements of the LCFS regulation with respect to the CARBOB.

c. For purposes of section 95485(a), except as provided in paragraph c.iii. of this provision:

i. the transferor under a. above must include the $Deficits^{XD}_{Incremental20XX}$ ~~$Deficits^{XD}_{Incremental}$~~, as defined and set forth in section 95486(b)(2)(A)1~~2.a~~., in the transferor's annual credits and deficits balance calculation set forth in section 95485(a)(2); and

ii. the recipient under b. above must include $Deficits^{XD}_{Base}$, as defined and set forth in section 95486(b)(2)(A)1~~2.a~~., in the recipient's annual credits and deficits balance calculation set forth in section 95485(a)(2).

iii. Paragraphs c.i and c.ii. above notwithstanding, the transferor and recipient of CARBOB may, by the time the ownership is transferred, specify by written contract which party is responsible for accounting for the base deficit and incremental deficit In the annual credits and deficits balance calculation set forth in section 95485(a)(2).

3. *Transfer of CARBOB or Gasoline to a Producer or Importer and Retaining Compliance Obligation.* Section 95484(a)(1)(B)2. notwithstanding, a regulated party transferring ownership of CARBOB to a producer or importer may elect to remain the regulated party and retain the LCFS compliance obligation for the transferred CARBOB by providing the recipient at the time of transfer with a product transfer document that prominently states that the transferor has elected to remain the regulated party with respect to the CARBOB.

4. *If Recipient Is Not a Producer or Importer, Regulated Party Transferring CARBOB Remains Regulated Party Unless Specified Conditions Are Met.* When a person who is the regulated party for CARBOB transfers ownership of the CARBOB to a person who is not a producer or importer, the transferor remains the regulated party unless the conditions of section 95484(a)(1)(B)5. are met.

5. *Conditions Under Which a Non-Producer and Non-Importer Acquiring Ownership of CARBOB Becomes the Regulated Party.* A person, who is neither a producer nor an importer and who acquires ownership of CARBOB from the regulated party, becomes the regulated party for the CARBOB if, by the time ownership is transferred, the two parties agree by written contract that the person acquiring ownership accepts the LCFS compliance obligation as the regulated party. For the transfer of regulated party obligations to be effective, the transferor must also provide the recipient a product transfer document that prominently states the information specified in paragraphs a. and b. below, and the transferor and recipient must meet the requirements specified in paragraph c., as set forth below:

    a. the volume and average carbon intensity of the transferred CARBOB. ~~For a transferor that is a regulated party subject to section 95486(b)(2)(A)2., the~~ <u>The </u>transferor of CARBOB may report as the “average carbon intensity” on the product transfer document the total carbon intensity value for CARBOB as shown in the Carbon Intensity Lookup Table; and

    b. the recipient is now the regulated party for the acquired CARBOB and accordingly is responsible for meeting the requirements of the LCFS regulation with respect to the CARBOB.

c. For purposes of section 95485(a), except as provided in paragraph c.iii. of this provision:

i. the transferor under a. above must include the $\underline{Deficits^{XD}_{Incremental20XX}}$ $\cancel{Deficits^{XD}_{Incremental}}$, as defined and set forth in section 95486(b)(2)(A)1~~2.a~~., in the transferor's annual credits and deficits balance calculation set forth in section 95485(a)(2); and

ii. the recipient under b. above must include $Deficits^{XD}_{Base}$, as defined and set forth in section 95486(b)(2)(A)1~~2.a~~., in the recipient's annual credits and deficits balance calculation set forth in section 95485(a)(2).

iii. Paragraphs c.i and c.ii. above notwithstanding, the transferor and recipient of CARBOB may, by the time the ownership is transferred, specify by written contract which party is responsible for accounting for the base deficit and incremental deficit In the annual credits and deficits balance calculation set forth in section 95485(a)(2).

(C) *Effect of Transfer By Regulated Party of Oxygenate to Be Blended With CARBOB.*

1. *Person Acquiring the Oxygenate Becomes the Regulated Party Unless Specified Conditions Are Met.* Except as provided in section 95484(a)(1)(C)2., when a person who is the regulated party for oxygenate to be blended with CARBOB transfers ownership of the oxygenate before it has been blended with CARBOB, the recipient of ownership of the oxygenate (i.e., the transferee) becomes the regulated party for it. The transferor must provide the recipient a product transfer document that prominently states:

a. the volume and carbon intensity of the transferred oxygenate; and
b. the recipient is now the regulated party for the acquired oxygenate and accordingly is responsible for

meeting the requirements of the LCFS with respect to the oxygenate.

2. *Transfer of Oxygenate and Retaining Compliance Obligation.* Section 95484(a)(1)(C)1. notwithstanding, a regulated party transferring ownership of oxygenate may elect to remain the regulated party and retain the LCFS compliance obligation for the transferred oxygenate by providing the recipient at the time of transfer with a product transfer document that prominently states that the transferor has elected to remain the regulated party with respect to the oxygenate.

(D) *Effect of Transfer by a Regulated Party of Gasoline to be Blended With Additional Oxygenate.* A person who is the sole regulated party for a batch of gasoline and is transferring ownership of the gasoline to another party that will be combining it with additional oxygenate may transfer his or her obligations as a regulated party if all of the conditions set forth below are met.

1. Blending the additional oxygenate into the gasoline is not prohibited by title 13, California Code of Regulations, section 2262.5(d).

2. By the time ownership is transferred the two parties agree by written contract that the person acquiring ownership accepts the LCFS compliance obligations as a regulated party with respect to the gasoline.

3. The transferor provides the recipient a product transfer document that prominently states the information specified in paragraphs a. and b. below, and the transferor and recipient must meet the requirements specified in paragraph c., as set forth below:

a. the volume and average carbon intensity of the transferred gasoline. ~~For a transferor that is a regulated party subject to section 95486(b)(2)(A)2., the~~ The transferor of CARBOB may use the total carbon intensity value for CARBOB along with the carbon intensity for the oxygenate, as shown in the Carbon Intensity Lookup Table, for calculating the "average carbon intensity" on the product transfer document; and

b. the recipient is now the regulated party for the acquired gasoline and accordingly is responsible for meeting the requirements of the LCFS regulation with respect to the gasoline.

c. For purposes of section 95485(a), except as provided in paragraph c.iii. of this provision:

i. the transferor under a. above must include the $\underline{Deficits^{XD}_{Incremental20XX}}$ ~~$Deficits^{XD}_{Incremental}$~~, as defined and set forth in section 95486(b)(2)(A)1~~2.a.~~, in the transferor's annual credits and deficits balance calculation set forth in section 95485(a)(2); and

ii. the recipient under b. above must include , as defined and set forth in section 95486(b)(2)(A)1~~2.a.~~, in the recipient's annual credits and deficits balance calculation set forth in section 95485(a)(2).

iii. Paragraphs c.i and c.ii. above notwithstanding, the transferor and recipient of CARBOB may, by the time the ownership is transferred, specify by written contract which party is responsible for accounting for the base deficit and incremental deficit in the annual credits and deficits balance calculation set forth in section 95485(a)(2).

4. The written contract between the parties includes an agreement that the recipient of the gasoline will be blending additional oxygenate into the gasoline.

(E) *Effect of Transfer by a Regulated Party of Oxygenate to be Blended With Gasoline.* Where oxygenate is added to gasoline, the regulated party with respect to the oxygenate is initially the producer or importer of the oxygenate. Transfers of the oxygenate are subject to section 95484(a)(1)(C).

(2) *Regulated Party for Diesel Fuel and Diesel Fuel Blends.*

(A) *Designation of Producers and Importers as Regulated Parties.*

1. *Where Biomass-Based Diesel Is Added to Downstream Diesel Fuel.*
For a diesel fuel blend consisting of diesel fuel and biomass-based diesel added downstream from the California facility

at which the diesel fuel was produced or imported, the regulated party is initially the following:

a. With respect to the diesel fuel, the regulated party is the producer or importer of the diesel fuel; and

b. With respect to the biomass-based diesel, the regulated party is the producer or importer of the biomass-based diesel.

2. *All Other Diesel Fuels.* For any other diesel fuel that does not fall within section 95484(a)(2)(A)1., the regulated party is the producer or importer of the diesel fuel.

(B) *Effect of Transfer of Diesel Fuel and Diesel Fuel Blends by Regulated Party.*

1. *Threshold Determination Whether Recipient of Diesel Fuel or Diesel Fuel Blend is a Producer or Importer.* Whenever a person who is the regulated party for diesel fuel or a diesel fuel blend transfers ownership before it has been transferred from its final distribution facility, the recipient must notify the transferor whether the recipient is a producer or importer for purposes of this section 95484(a)(2)(B).

2. *Producer or Importer Acquiring Diesel Fuel or Diesel Fuel Blend Becomes the Regulated Party Unless Specified Conditions Are Met.* Except as provided for in section 95484(a)(2)(B)3., when a person who is the regulated party for diesel fuel or a diesel fuel blend transfers ownership to a producer or importer before it has been transferred from its final distribution facility, the recipient of ownership of the diesel fuel or diesel fuel blend (i.e., the transferee) becomes the regulated party for it. The transferor must provide the recipient a product transfer document that prominently states the information specified in paragraphs a. and b. below, and the transferor and recipient must meet the requirements specified in paragraph c., as set forth below:

a. the volume and average carbon intensity of the transferred diesel fuel or diesel fuel blend. ~~For a transferor that is a regulated party subject to section 95486(b)(2)(A)2., the~~ The transferor of diesel fuel or diesel fuel blend may report as the “average carbon intensity” on the product transfer document the total carbon intensity value for “diesel” (ULSD) as shown in the Carbon Intensity Lookup Table; and

b. the recipient is now the regulated party for the acquired diesel fuel or diesel fuel blend and accordingly is responsible for meeting the requirements of the LCFS regulation with respect to it.

c. For purposes of section 95485(a), except as provided in paragraph c.iii. of this provision:

i. the transferor under a. above must include the $\underline{Deficits^{XD}_{Incremental20XX}}$ $\cancel{Deficits^{XD}_{Incremental}}$, as defined and set forth in section 95486(b)(2)(A)1~~2.a.~~, in the transferor’s annual credits and deficits balance calculation set forth in section 95485(a)(2); and

ii. the recipient under b. above must include $Deficits^{XD}_{Base}$, as defined and set forth in section 95486(b)(2)(A)1~~2.a.~~, in the recipient’s annual credits and deficits balance calculation set forth in section 95485(a)(2).

iii. Paragraphs c.i and c.ii. above notwithstanding, the transferor and recipient of diesel fuel or diesel fuel blend may, by the time the ownership is transferred, specify by written contract which party is responsible for accounting for the base deficit and incremental deficit In the annual credits and deficits balance calculation set forth in section 95485(a)(2).

3. *Transfer of Diesel Fuel or Diesel Fuel Blend to a Producer or Importer and Retaining Compliance Obligation.* Section 95484(a)(2)(B)2. notwithstanding, a regulated party transferring ownership of diesel fuel or diesel fuel blend to a producer or importer may elect to remain the regulated party and retain the LCFS compliance obligation for the transferred diesel fuel or diesel fuel blend by providing the recipient at the time of transfer with a product transfer document that prominently states that the transferor has elected to remain the regulated party with respect to the diesel fuel or diesel fuel blend.

4. *If Recipient Is Not a Producer or Importer, Regulated Party Transferring Diesel Fuel or Diesel Fuel Blend Remains Regulated Party Unless Specified Conditions Are Met.* When a person who is the regulated party for diesel fuel or a diesel fuel blend transfers ownership of the diesel fuel or diesel fuel blend to a person who is not a producer or importer, the transferor remains the regulated party unless the conditions of section 95484(a)(2)(B)5. are met.

5. *Conditions Under Which a Non-Producer and Non-Importer Acquiring Ownership of Diesel Fuel or Diesel Fuel Blend Becomes the Regulated Party.* A person, who is neither a producer nor an importer and who acquires ownership of diesel fuel or a diesel fuel blend from the regulated party, becomes the regulated party for the diesel fuel or diesel fuel blend if, by the time ownership is transferred, the two parties agree by written contract that the person acquiring ownership accepts the LCFS compliance obligation as the regulated party. For the transfer of regulated party obligations to be effective, the transferor must also provide the recipient a product transfer document that prominently states the information specified in paragraphs a. and b. below, and the transferor and recipient must meet the requirements specified in paragraph c., as set forth below:

    a. the volume and average carbon intensity of the transferred diesel fuel or diesel fuel blend. ~~For a transferor that is a regulated party subject to section 95486(b)(2)(A)2., the~~ The transferor of diesel fuel or diesel fuel blend may report as the "average carbon intensity" on the product transfer document the total carbon intensity value for "diesel" (ULSD) as shown in the Carbon Intensity Lookup Table; and

    b. the recipient is now the regulated party for the acquired diesel fuel or diesel fuel blend and accordingly is responsible for meeting the requirements of the LCFS regulation with respect to the diesel fuel or diesel fuel blend.

    c. For purposes of section 95485(a), except as provided in paragraph c.iii. of this provision:

        i. the transferor under a. above must include the $\underline{Deficits^{XD}_{Incremental20XX}}$ $\cancel{Deficits^{XD}_{Incremental}}$, as defined and set forth in section 95486(b)(2)(A)1~~2.a~~., in the transferor's annual credits and deficits balance calculation set forth in section 95485(a)(2); and

ii. the recipient under b. above must include $Deficits^{XD}_{Base}$, as defined and set forth in section 95486(b)(2)(A)1~~2.a.~~, in the recipient's annual credits and deficits balance calculation set forth in section 95485(a)(2).

iii. Paragraphs c.i and c.ii. above notwithstanding, the transferor and recipient of diesel fuel or diesel fuel blend may, by the time the ownership is transferred, specify by written contract which party is responsible for accounting for the base deficit and incremental deficit In the annual credits and deficits balance calculation set forth in section 95485(a)(2).

(C) *Effect of Transfer By Regulated Party of Biomass-Based Diesel to Be Blended With Diesel Fuel.*

1. *Person Acquiring the Biomass-Based Diesel Becomes the Regulated Party Unless Specified Conditions Are Met.*

Except as provided in section 95484(a)(2)(C)2., when a person who is the regulated party for biomass-based diesel to be blended with diesel fuel transfers ownership of the biomass-based diesel before it has been blended with diesel fuel, the recipient of ownership of the biomass-based diesel (i.e., the transferee) becomes the regulated party for it. The transferor must provide the recipient a product transfer document that prominently states:

a. the volume and carbon intensity of the transferred biomass-based diesel; and

b. the recipient is now the regulated party for the acquired biomass-based diesel and accordingly is responsible for meeting the requirements of the LCFS with respect to the biomass-based diesel.

2. *Transfer of Biomass-Based Diesel and Retaining Compliance Obligation.*

Section 95484(a)(2)(C)1. notwithstanding, the transferor may elect to remain the regulated party and retain the LCFS compliance obligation for the transferred biomass-based diesel by providing the recipient at the time of transfer with a product transfer document that prominently states that the transferor has elected to remain the regulated party with respect to the biomass-based diesel.

(3) *Regulated Party For Liquid Alternative Fuels Not Blended With Gasoline Or Diesel Fuel.* For a liquid alternative fuel, including but not limited to neat denatured ethanol and neat biomass-based diesel, that is not blended with gasoline or diesel fuel, or with any other petroleum-derived fuel, the regulated party is the producer or importer of the liquid alternative fuel.

(4) *Regulated Party For Blends Of Liquid Alternative Fuels And Gasoline Or Diesel Fuel.*

(A) *Designation of producers and Importers as regulated parties.* For a transportation fuel that is a blend of liquid alternative fuel and gasoline or diesel fuel – but that does not itself constitute gasoline or diesel fuel – the regulated party is the following:

(1) With respect to the alternative fuel component, the regulated party is the person who produced the liquid alternative fuel in California or imported it into California; and

(2) With respect to the gasoline or diesel fuel component, the regulated party is the person who produced the gasoline or diesel fuel in California or imported it into California.

(B) *Transfer Of A Blend Of Liquid Alternative Fuel And Gasoline Or Diesel Fuel And Compliance Obligation.* Except as provided for in section 95484(a)(4)(C), on each occasion that a person transfers ownership of fuel that falls within section 95484(a)(4) ("alternative liquid fuel blend") before it has been transferred from its final distribution facility, the recipient of ownership of such an alternative liquid fuel blend (i.e., the transferee) becomes the regulated party for that alternative liquid fuel blend. The transferor shall provide the recipient a product transfer document that prominently states:

1. the volume and average carbon intensity of the transferred alternative liquid fuel blend; and

2. the recipient is now the regulated party for the acquired alternative liquid fuel blend and accordingly is responsible for meeting the requirements of the LCFS regulation with respect to the alternative liquid fuel blend.

(C) *Transfer Of A Blend Of Liquid Alternative Fuel And Gasoline Or Diesel Fuel And Retaining Compliance Obligation.* Section 95484(a)(4)(B) notwithstanding, the transferor may elect to remain the regulated party and retain the LCFS compliance obligation for the transferred alternative liquid fuel blend by written contract with the recipient. The transferor shall provide the recipient with a product transfer document that identifies the volume and average carbon intensity of the transferred alternative liquid fuel blend.

(5) *Regulated Parties for Natural Gas (Including CNG, LNG, and Biogas).*

(A) *Designation of Regulated Parties for Fossil CNG and Biogas CNG.*

1. *Where Biogas CNG is Added to Fossil CNG.*

For fuel consisting of a fossil CNG and biogas CNG blend, the regulated party is initially the following:

a. With respect to the fossil CNG, the regulated party is the person that owns the natural gas fueling equipment at the facility at which the fossil CNG and biogas CNG blend is dispensed to motor vehicles for their transportation use; and

b. With respect to the biogas CNG, the regulated party is the producer or importer of the biogas CNG.

2. *Where No Biogas CNG is Added to Fossil CNG.* For fuel consisting solely of fossil CNG, the regulated party is the person that owns the natural gas fueling equipment at the facility at which the fossil CNG is dispensed to motor vehicles for their transportation use.

(B) *Designation of Regulated Parties for Fossil LNG and Biogas LNG.*

1. *Where Biogas LNG is Added to Fossil LNG.*

For a fuel consisting of a fossil LNG and biogas LNG blend, the regulated party is initially the following:

a. With respect to the fossil LNG, the regulated party is the person that owns the fossil LNG when it is transferred to the facility at which the liquefied blend is dispensed to motor vehicles for their transportation use; and

b. With respect to the biogas, the regulated party is the producer or importer of the biogas LNG.

2. *Where No Biogas LNG is Added to Fossil LNG.* For fuel consisting solely of fossil LNG, the regulated party is initially the person that owns the fossil LNG when it is transferred to the facility at which the fossil LNG is dispensed to motor vehicles for their transportation use.

(C) *Designation of Regulated Party for Biogas CNG or Biogas LNG Supplied Directly to Vehicles for Transportation Use.* For fuel consisting solely of biogas CNG or biogas LNG that is produced in California and supplied directly to vehicles in California for their transportation use without first being blended into fossil CNG or fossil LNG, the regulated party is initially the producer of the biogas CNG or biogas LNG.

(D) *Effect of Transfer of Fuel by Regulated Party.*

1. *Transferor Remains Regulated Party Unless Conditions Are Met.*

When a person who is the regulated party for a fuel specified in section 95484(a)(5)(A), (B), or (C) transfers ownership of the fuel, the transferor remains the regulated party unless the conditions of section 95484(a)(5)(D)2. are met.

2. *Conditions Under Which a Person Acquiring Ownership of a Fuel Becomes the Regulated Party.* Section 95484(a)(5)(D)1. notwithstanding, a person acquiring ownership of a fuel specified in section 95484(a)(5)(A), (B), or (C) from the regulated party becomes the regulated party for that fuel if, by the time ownership is transferred, the two parties agree by written contract that the person acquiring ownership accepts the LCFS compliance obligation as the regulated party. For the transfer of regulated party obligations to be effective, the transferor must also provide the recipient a product transfer document that prominently states:

a. the volume and average carbon intensity of the transferred fuel; and

b. the recipient is now the regulated party for the acquired fuel and accordingly is responsible for meeting the requirements of the LCFS regulation with respect to the acquired fuel.

(6) *Regulated Parties for Electricity.* For electricity used as a transportation fuel, the party who is eligible to opt-in as a regulated party is determined as specified below:

(A) For transportation fuel supplied through electric vehicle (EV) charging equipment in a single or multi-family residence, the Electrical Distribution Utility is eligible to opt-in as the regulated party in their service territory. To receive credit for electricity supplied as a transportation fuel, the Electrical Distribution Utility must:

1. Use all credit proceeds as direct benefits for current EV customers.

2. Educate the public on the benefits of EV transportation (including environmental benefits and costs of EV charging as compared to gasoline). These efforts may include, but are not limited to:

a. public meetings
b. EV dealership flyers
c. utility customer bill inserts
d. radio and/or television advertisements
e. webpage content

3. Provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid.

4. Include in annual compliance reporting an itemized summary of efforts to meet requirements 1 through 3 above; costs associated with meeting the requirements; an accounting of credits generated, sold, and banked; and an accounting of the number of EV s known to be operating in the service territory. ARB will post the annual compliance reports for public review by May 31st of each year.

(B) For transportation fuel supplied through public access EV charging equipment, the third-party non-utility Electric Vehicle Service

Provider (EVSP) or Electrical Distribution Utility that has installed the equipment, or had an agent install the equipment, and who has a contract with the property owner or lessee where the equipment is located to maintain or otherwise service the charging equipment, is eligible to opt-in as the regulated party.

If the EVSP is not the regulated party for a specific volume of fuel, or has not fully complied with the requirements of this subarticle, the Electrical Distribution Utility is eligible to opt-in as the regulated party with EO approval. To receive credit for transportation fuel supplied through public access EV charging equipment, the regulated party must:

1. Use all credit proceeds as direct benefits for current EV customers.

2. Educate the public on the benefits of EV transportation (including environmental benefits and costs of EV charging as compared to gasoline). These efforts may include, but are not limited to:

   a. public meetings
   b. EV dealership flyers
   c. utility customer bill inserts
   d. radio and/or television advertisements
   e. webpage content

3. Provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid,

4. Include in annual compliance reporting an itemized summary of efforts to meet requirements 1 through 3 above; costs associated with meeting the requirements; an accounting of credits generated, sold, and banked; and an accounting of the number of operating EV charging stations and the number of charging incidents. ARB will post the annual compliance reports for public review by May 31st of each year.

(C) For transportation fuel supplied to a fleet of three or more EVs, a company operating a fleet (fleet operator) is eligible to be a regulated party. If the fleet operator is not the regulated party for a specific volume of fuel, or has not otherwise fully complied with the requirements of this subarticle, the Electrical Distribution Utility is eligible to opt-in as the regulated party with EO approval. For transportation fuel supplied to a fleet of less than three EVs, the

Electrical Distribution Utility is eligible to be the regulated party. To receive credit for transportation fuel supplied to an EV fleet, the regulated party must include in annual compliance reporting an accounting of the number of EVs in the fleet.

(D) For transportation fuel supplied through private access EV charging equipment at a business or workplace, the business owner is eligible to be a regulated party. If the business owner is not the regulated party for a specific volume of fuel, or has not fully complied with the requirements of this subarticle, the Electrical Distribution Utility is eligible to opt-in as the regulated party with EO approval. To receive credit for transportation fuel supplied through private access EV charging equipment at a business or workplace, the regulated party must:

1. Educate employees on the benefits of EV transportation (including environmental benefits and costs of EV charging as compared to gasoline) through outreach efforts that may include, but are not limited to:

   a. employee meetings
   b. public meetings
   c. EV dealership flyers
   d. employee flyers
   e. webpage content
   f. preferred parking

2. Include in annual compliance reporting a summary of efforts to meet requirement 1, as well as an accounting of the number of EVs known to be charging at the business.

(E) In the event that there is measured on-road electricity as a transportation fuel that is not covered in paragraphs (B) through (D) above, the Electrical Distribution Utility is eligible to opt-in as the regulated party with EO approval. To receive credit for this transportation fuel, the Electrical Distribution Utility must meet all requirements set forth in section 95484(a)(6)(A).

~~(A) The load-serving entity or other provider of electricity services, unless section 95484(a)(6)(B), (C), or (D) below applies. "Load-serving entity" has the same meaning specified in Public Utilities Code (PUC) section 380. "Provider of electricity services" means a local publicly-owned utility, retail seller (as defined in PUC section 399.12(g)), or any other person that supplies electricity to the vehicle charging equipment;~~

~~(B) The electricity services supplier, where "electricity services supplier" means any person or entity that provides bundled charging infrastructure and other electric transportation services and provides access to vehicle charging under contract with the vehicle owner or operator;~~

~~(C) The owner and operator of the electric-charging equipment, provided there is a contract between the charging equipment owner-operator and the provider of electricity services specifying that the charging equipment owner-operator is the regulated party;~~

~~(D) The owner of a home with electric vehicle-charging equipment, provided there is a contract between the homeowner and provider of electricity services specifying that the homeowner may acquire credits.~~

(7) *Regulated Parties for Hydrogen Or A Hydrogen Blend.*

(A) *Designation of Regulated Party at Time Finished Fuel is Created.*

For a volume of finished fuel consisting of hydrogen or a blend of hydrogen and another fuel ("finished hydrogen fuel"), the regulated party is initially the person who owns the finished hydrogen fuel at the time the blendstocks are blended to make the finished hydrogen fuel.

(B) *Transfer of Ownership and Retaining Compliance Obligation.* Except as provided for in section 95484(a)(7)(C), when a person who is the regulated party transfers ownership of a finished hydrogen fuel to another person, the transferor remains the regulated party.

(C) *Conditions Under Which a Person Acquiring Ownership of Finished Hydrogen Fuel Becomes the Regulated Party.* Section 95484(a)(7)(B) notwithstanding, a person who acquires ownership of finished hydrogen fuel becomes the regulated party for the fuel if, by the time ownership is transferred, the two parties (transferor and recipient) agree by written contract that the person acquiring ownership accepts the LCFS compliance obligation as the regulated party. For the transfer of regulated party obligations to be effective, the transferor must also provide the recipient a product transfer document that prominently states:

1. the volume and average carbon intensity of the transferred finished hydrogen fuel; and

2. the recipient is now the regulated party for the acquired finished hydrogen fuel and accordingly is responsible for meeting the requirements of the LCFS regulation with respect to the acquired finished hydrogen fuel.

~~(b) *Calculation of Credit Balance and Annual Compliance Obligation.*~~

~~(1) *Compliance Period.* Beginning in 2011 and every year thereafter, the annual compliance period is January 1 through December 31 of each year.~~

~~(2) *Calculation of Compliance Obligation and Credit Balance at the End of a Compliance Period.* A regulated party must calculate the credit balance at the end of a compliance period as follows:~~

~~*Compliance Obligation = Deficits*~~ ^{Gen} ~~*+ Deficits*~~ $^{Carried\ Over}$

~~*Credit Balance = Credits*~~ ^{Gen} ~~*+ Credits*~~ ^{Acquired} ~~–~~
~~*Sum of (Credits*~~ ^{retired} ~~*+ Credits*~~ ^{Sold} ~~*+ Credits*~~ ^{Exported}~~)~~

~~*Credit Balance = Credits*~~ ^{Gen} ~~*+ Credits*~~ ^{CarriedOver} ~~*+ Credits*~~ ^{Acquired}
~~*+ Deficits*~~ ^{Gen} ~~*— Credits*~~ ^{Sold} ~~*— Credits*~~ ^{Exported} ~~*— Credits*~~ ^{Retired}

~~where:~~

~~*Deficits*~~ ^{Gen} ~~are the total deficits generated pursuant to section 95485(a) for the current compliance period;~~

~~*Deficits*~~ $^{Carried\ Over}$ ~~are the deficits carried over from the previous compliance period;~~

~~*Credits*~~ ^{Gen} ~~areis the total credits generated pursuant to section 954885(a) for the current compliance period;~~

~~*Credits*~~ ^{CarriedOver} ~~is the credits or deficits carried over from the previous compliance period;~~

~~*Credits*~~ ^{Acquired} ~~areis the total credits purchased or otherwise acquired, including carry back credits acquired pursuant to section 95488(a)(3)in the current compliance period;~~

~~*Deficits*~~ ^{Gen} ~~is the total deficits generated pursuant to section 95485(a) for the current compliance period;~~

~~*Credits*~~ ^{Sold} ~~areis the total credits sold or otherwise transferred in the current compliance period;~~

~~$Credits^{Exported}$ areis the total credits exported to programs outside the LCFS for the current compliance period; and~~

~~$Credits^{Retired}$ areis the total credits retired within the LCFS for the current compliance period.~~

~~(3) *Compliance Demonstration.* A regulated party's annual compliance obligation is met when the regulated party demonstrates via its annual report that it possessed and has retired a number of credits from its credit account (established pursuant to section 95488) that is equal to its compliance obligation.~~

~~(34) *Deficit Carryover.* A regulated party that does not retire sufficient credits to fully offset its compliance obligation creates a negative credit balance in a compliance period. The regulated party with a negative credit balance in a compliance period may carry over the deficit to the next compliance period, without penalty, if both the following conditions are met:~~

~~(A) the regulated party fully met its annual compliance obligation for has a credit balance greater than or equal to zero in the previous compliance period; and~~

~~(B) the number of *Credits* ^{retired} for the current annual compliance period is at least equal to 90 percent of the current annual compliance obligation. sum of the magnitude of $Credits^{Gen}$, $Credits^{CarriedOver}$, and $Credits^{Acquired}$ is greater than or equal to 90 percent of the sum of the magnitude of $Deficits^{Gen}$, $Credits^{Sold}$, $Credits^{Exported}$, $Credits^{Retired}$ and for the current compliance period.~~

~~(45) *Deficit Reconciliation.*~~

~~(A) A regulated party that meets the conditions of deficit carryover, as specified in section 95481(b)(34), must eliminate any deficit generated in a given compliance period by the end of the next compliance period. A deficit may be eliminated only by retirement of an equal amount of generated credits (*Credits* ^{Gen}), by acquisition of an equal amount of credits from another regulated party (*Credits* $_{Acquired}$), or by any combination of these two methods. retained credits ($Credits^{CarriedOver}$), by purchase of an equal amount of credits from another regulated party, or by any combination of these two methods.~~

~~(B) If the conditions of deficit carryover as specified in section 95481(b)(34) are not met, a regulated party is subject to penalties~~

~~to the extent permitted under State law. In addition, the regulated party must eliminate any deficit generated in a given compliance period by the end of the next compliance period. A deficit may be eliminated only by retirement of an equal amount of generated credits ($Credits^{Gen}$), by acquisition of an equal amount of credits from another regulated party ($Credits^{Acquired}$), or by any combination of these two methods. a regulated party must eliminate any deficit generated in a given compliance period by the end of the next compliance period. A deficit may be eliminated only by retirement of an equal amount of retained credits ($Credits^{CarriedOver}$), by purchase of an equal amount of credits from another regulated party, or by any combination of these two methods. In addition, the regulated party is subject to penalties to the extent permitted under State law.~~

~~(C) A regulated party that is reconciling in the current compliance period a deficit from the previous compliance period under (A) or (B) above remains responsible for meeting the LCFS regulation requirements during the current compliance period.~~

(~~c~~b) *Reporting Requirements.*

(1) *Reporting Frequency*. A regulated party must submit to the Executive Officer quarterly progress reports and annual compliance reports, as specified in sections 95484(b~~c~~)(3) and 95484(b~~c~~)(4). The reporting frequencies for these reports are set forth below:

(A) *Quarterly Progress Reports For All Regulated Parties.* Beginning 2010 and each year thereafter, a regulated party must submit quarterly progress reports to the Executive Officer by:

1. May 31st – for the first calendar quarter covering January through March;

2. August 31st – for the second calendar quarter covering April through June;

3. November 30th – for the third calendar quarter covering July through September; and

4. February 28th (29th in a leap year) – for the fourth calendar quarter covering October through December.

(B) *Annual Compliance Reports.* By April 30th of 2011, a regulated party must submit an annual report for calendar year 2010. By

April 30th of 2012 and each year thereafter, a regulated party must provide an annual compliance report for the prior calendar year.

(2) *How ~~T~~to Report.* A regulated party must submit an annual compliance and quarterly progress report using the online LCFS Reporting Tool (LRT), an interactive, secured internet web-based system. The LRT is available at: www.arb.ca.gov/lcfsrt.~~by using an interactive, secured internet web-based form~~.

The regulated party is solely responsible for ensuring that the Executive Officer receives its progress and compliance reports by the dates specified in section 95484(b~~c~~)(1). The Executive Officer shall not be responsible for failure of electronically submitted reports to be transmitted to the Executive Officer. The report must contain a statement attesting to the report's accuracy and validity. The Executive Officer shall not deem an electronically submitted report to be valid unless the report is accompanied by a digital signature that meets the requirements of title 2, California Code of Regulations, section 22000 et seq.

(3) *General and Specific Reporting Requirements for Quarterly Progress Reports*. For each of its transportation fuels, a regulated party must submit a quarterly progress report that contains the information specified in Table 3 and meets the additional specific requirements set forth below:

(A) *Specific Quarterly Reporting Requirements (Except As Otherwise Noted) for Gasoline and Diesel Fuel.*

1. For each transfer of gasoline or diesel fuel that results in a transfer of the compliance obligation or retention of the compliance obligation by written contract, the regulated party must provide to the Executive Officer, within 10 business days of a request, the product transfer document containing the information identified in section 95484(a)(1)(B), (a)(1)(C), (a)(1)(D), (a)(2)(B), (a)(2)(C), (a)(4)(B), or (a)(4)(C), ~~(a)(5)(D), or (a)(7)(C),~~ whichever applies.

2. The carbon intensity value of each blendstock determined pursuant to section 95486.

3. The volume of each blendstock (in gal) per compliance period. For purposes of this provision only, except as provided in section 95484(b)(4)(B), the regulated party may report the total volume of each blendstock aggregated for each distinct carbon intensity value (e.g., X gallons of blendstock with A gCO2e/MJ, Y gallons of blendstock with B

gCO2e/MJ, etc.). ~~Further, if the regulated party is subject to section 95486(b)(2)(A)2. for fuel or blendstock derived from high carbon-intensity crude oil (HCICO), regulated party must report the E^{XD}_{HCICO} per compliance period, where E^{XD}_{HCICO} is defined in section 95486(b)(2)(A)2.a.~~

4. The volume of each petroleum blendstock, petroleum intermediate, and petroleum finished fuel (in gal) imported into California during each quarter. ~~All Renewable Identification Numbers (RINs) that are retired for facilities in California.~~

(B) *Specific Quarterly Reporting Requirements for Natural Gas (including CNG, LNG, and Biogas).* For each private access, public access, or home fueling facility to which the regulated party supplies CNG, LNG or biogas as a transportation fuel:

1. For CNG, the regulated party must report the amount of fuel dispensed (in scf) per compliance period for all light/medium-duty vehicles (LDV & MDV) and heavy-duty vehicles (HDV). For LNG, the regulated party must report the amount of fuel dispensed (in gal) per compliance period for all LDV & MDV and HDV;

2. Except as provided for in section 95484(b~~c~~)(3)(B)3., the regulated party must report the amount of fuel dispensed based on the use of separate fuel dispenser meters at each fuel dispenser;

3. In lieu of using separate meters at each fuel dispenser, the regulated party may report the amount of fuel dispensed at each facility using any other method that the regulated party demonstrates to the Executive Officer's satisfaction as being equivalent to or better than the use of separate fuel meters at each fuel dispenser in each fueling facility;

4. The carbon intensity value of the CNG, LNG, or biogas determined pursuant to section 95486.

(C) *Specific Quarterly Reporting Requirements for Electricity*. For electricity used as a transportation fuel, a regulated party must also submit the following:

1. For residential charging stations, the total electricity dispensed (in kWh) to all vehicles at each residence based on direct metering, which distinguishes electricity delivered

for transportation use. Before January 1, 2015, "based on direct metering" means either:

a. the use of direct metering (~~also called~~ either submetering or separate metering) to measure the electricity directly dispensed to all vehicles at each residential charging station; or

b. for households and residences only where direct metering has not been installed, the regulated party may report the total electricity dispensed at each residential charging station using another method that the regulated party demonstrates to the Executive Officer's satisfaction is substantially similar to the use of direct metering under section 95484(b~~c~~)(3)(C)1.a.~~.~~

Effective January 1, 2015, "based on direct metering" means only the use of direct metering as specified in section 95484(b~~c~~)(3)(C)1.a. above;

2. For each public access charging facility, the amount of electricity dispensed (in kW-hr);

3. For each fleet charging facility, the amount of fuel dispensed (in kW-hr).

4. For each workplace private access charging facility, the amount of electricity dispensed (in kW-hr).

~~4.~~5. The carbon intensity value of the electricity determined pursuant to section 95486.

(D) *Specific Quarterly Reporting Requirements for Hydrogen or a Hydrogen Blend.* For hydrogen or a hydrogen blend used as a transportation fuel, a regulated party must also submit the following:

1. For each private access fueling facility, the amount of fuel dispensed (in kg) by vehicle weight category: LDV & MDV and HDV.

2. For each public access filling station, the amount of fuel dispensed (in kg) by vehicle weight category: LDV & MDV and HDV.

3. The carbon intensity value of the hydrogen or the blendstocks used to produce the hydrogen blend determined

pursuant to section 95486.

(4) *General and Specific Reporting Requirements for Annual Compliance Reports.* A regulated party must submit an annual compliance report that meets, at minimum, the general and specific requirements specified in section 95484(b~~c~~)(3) above and the additional requirements set forth below:

(A) A regulated party must report the following:

1. The total credits and deficits generated by the regulated party in the current compliance period, calculated as per equations in section 95485(a);

2. Any credits carried over from the previous compliance period;

3. Any deficits carried over from the previous compliance period;

4. The total credits acquired from another party and identify the party from whom the credits were acquired;

5. The total credits sold or otherwise transferred and identify each party to whom those credits were transferred;

6. The total credits retired within the LCFS; and

7. The total credits exported to programs outside the LCFS.

(B) A producer of CARBOB, gasoline or diesel fuel must report, for each its refineries, the data listed below:

1. volume (in gal) and marketable crude oil name (MCON) of all crude oil supplied to the refinery in the current compliance period that was produced in California using thermal enhanced oil recovery (TEOR) methods;

2. volume (in gal) and MCON of all crude oil supplied to the refinery in the current compliance period that was produced in California using non-TEOR methods; and

3. volume (in gal), MCON, and Country (or State) of origin for all crude oil supplied to the refinery in the current compliance period that was imported.

(5) *Significant Figures*. The regulated party must report the following quantities as specified below:

(A) carbon intensity, expressed to the same number of significant figures as shown in the carbon intensity lookup table (Method 1);

(B) credits, expressed to the nearest whole metric ton CO2 equivalent;

(C) fuel volume in units specified in section 95484(b)(3) and (b)(4), expressed to the nearest whole unit applicable for that quantity; ~~expressed as follows:~~

~~1. a fuel volume greater than 1 million gasoline gallon equivalent (gge) must be expressed to the nearest 10,000 gge;~~

~~2. a fuel volume between 100,000 gge and 1 million gge, inclusive, must be expressed to the nearest 1,000 gge;~~

~~3. a fuel volume between 10,000 gge and 99,999 gge, inclusive, must be expressed to the nearest 100 gge; and~~

~~4. a fuel volume less than 9,999 gge must be expressed to the nearest 10 gge.~~

(D) any other quantity not specified in section 95484(b~~c~~)(5)(A) to 95484(b~~c~~)(5)(C) must be expressed to the nearest whole unit applicable for that quantity.

~~(E) *Rounding Intermediate Calculated Values.* A regulated party must use one of the following procedures for rounding intermediate calculated values for fuel quantity dispensed, blended, or sold in California; calculated carbon intensity values; calculated LCFS credits and deficits; and any other calculated or measured quantity required to be used, recorded, maintained, provided, or reported for the purpose determining a reported value under the LCFS regulation (17 CCR section 95480 et seq.):~~

~~1. ASTM E 29-08 (October 1, 2008), *Standard Practice for Using Significant Digits in Test Data to Determine Conformance with Specifications*, which is incorporated herein by reference; or~~

~~2. Any other practice that the regulated party has demonstrated to the Executive Officer's written satisfaction provides equivalent or better results as compared with the method specified in subsection 95484(c)(5)(E)1. above.~~

Table 3. Summary Checklist of Quarterly and Annual Reporting Requirements.

Parameters to Report	Gasoline & Diesel fuel	CNG & LNG	Electricity	Hydrogen Or Hydrogen Blends	Neat Ethanol or Biomass-Based Diesel Fuels
Company or organization name	x	x	x	x	x
Reporting period	x	x	x	x	x
~~Type of fuel~~ Fuel pathway code	x	x	x	x	x
~~Blended fuel (yes/no)~~ Transaction type	x	x	x	x	x
~~If yes, number of blendstocks~~ Transaction date	x	x	~~n/a~~ x	x	x
~~Type(s) of blendstock~~ Business Partner	x	x	~~n/a~~ x	x	x
~~RIN numbers~~ Biofuel Production Facility	x	~~n/a~~ x	n/a	~~n/a~~ x	x
~~Blendstock feedstock~~ Physical pathway code	x	x	~~n/a~~ x	x	x
~~Feedstock origin~~ Aggregation	x	x	~~n/a~~	x	x
~~Production process~~ Application / EER	x	x	x~~*~~	x	x
Volume ~~Amount~~ of each blendstock (~~MJ~~Gal)	x	~~X~~ n/a	n/a	~~X~~ n/a	~~X~~ n/a
~~**The CI of the fuel or blendstock ($CI^{XD}_{reported}$)~~ Volume of each petroleum blendstock, petroleum intermediate, and petroleum finished fuel imported into California (gal)	~~x~~	~~x~~	~~x~~	~~x~~	~~x~~
Amount of each fuel used as gasoline replacement (MJ)	x	x	x	x	x
Amount of each fuel used as diesel fuel replacement (MJ)	x	x	x	x	x
**Credits/deficits generated per quarter (MT)	x	x	x	x	x
For Annual Reporting (in addition to the items above)					
**Credits and Deficits generated per year (MT)	x	x	x	x	x
**Credits/deficits carried over from the previous year (MT), if any	x	x	x	x	x
**Credits acquired from another party (MT), if any	x	x	x	x	x
**Credits sold to another party (MT), if any	x	x	x	x	x
**Credits exported to another program (MT), if any	x	x	x	x	x
**Credits retired within LCFS (MT) , if any	x	x	x	x	x
Volume (gal) and MCON of crude oil refining in California production facility	x	n/a	n/a	n/a	n/a

~~ Optional. However if qualifying the CI value of electricity, under method 2A, that is different from CA Marginal electricity value, production process must be reported.~~ **Value will be calculated or stored in the compliance tool.*

(~~d~~c) *Recordkeeping and Auditing.*

(1) A regulated party must retain all of the following records for at least 3 years and must provide such records within 20 days of a written request received from the Executive Officer or his/her designee before expiration of the period during which the records are required to be retained:

(A) product transfer documents;

(B) copies of all data and reports submitted to the Executive Officer;

(C) records related to each fuel transaction; and

(D) records used for compliance or credit calculations.

(2) *Evidence of Physical Pathway.* A regulated party may not generate credits pursuant to section 95485 unless it has demonstrated or provided a demonstration to the Executive Officer that a physical pathway exists, for each of the transportation fuels and blendstocks for which it is responsible under the LCFS regulation, and that each physical pathway has been approved by the Executive Officer pursuant to this section 95484(c~~d~~)(2). For purposes of this provision, “demonstrated” and “demonstration” includes any combination of either (i) a showing by the regulated party using its own documentation; or (ii) a showing by the regulated party that incorporates by reference documentation voluntarily submitted by another regulated party or a non-regulated party fuel producer, provided the documentation applies to and accurately represents the regulated party’s transportation fuel or blendstock;

“Physical pathway” means the applicable combination of actual fuel delivery methods, such as truck routes, rail lines, gas/liquid pipelines, electricity transmission lines, and any other fuel distribution methods, through which the regulated party reasonably expects the fuel to be transported under contract from the entity that generated or produced the fuel, to any intermediate entities, and ending at the fuel blender, producer, importer, or provider in California.

The Executive Officer shall not approve a physical pathway demonstration unless the demonstration meets the following requirements:

(A) *Initial Demonstration of Delivery Methods.* The regulated party must provide an initial demonstration of the delivery methods comprising the physical pathway for each of the regulated party’s fuels. The initial demonstration must include documentation in sufficient detail for the Executive Officer to verify the existence of the physical pathway’s delivery methods.

The documentation must include a map(s) that shows the truck/rail lines or routes, pipelines, transmission lines, and other delivery methods (segments) that, together, comprise the physical pathway. If more than one company is involved in the delivery, each segment on the map must be linked to a specific company that is expected to transport the fuel through each segment of the physical pathway. The regulated party must provide the contact information for each such company, including the contact name, mailing address, phone number, and company name.

(B) *Initial Demonstration of Fuel Introduced Into the Physical Pathway.*

For each blendstock or alternative fuel for which LCFS credit is being claimed, the regulated party must provide evidence showing that a specific volume of that blendstock or fuel was introduced by its provider into the physical pathway identified in section 95484(c~~d~~)(2)(A). The evidence may include, but is not limited to, a written purchase contract or transfer document for the volume of blendstock or alternative fuel that was introduced or otherwise delivered into the physical pathway.

(C) *Initial Demonstration of Fuel Removed From the Physical Pathway.* For each specific volume of blendstock or alternative fuel identified in section 95484(c~~d~~)(2)(B), the regulated party must provide evidence showing that the same volume of blendstock or fuel was removed from the physical pathway in California by the regulated party and provided for transportation use in California. The evidence may include, but is not limited to, a written sales contract or transfer document for the volume of blendstock or alternative fuel that was removed from or otherwise extracted out of the physical pathway in California.

(D) *Subsequent Demonstration of Physical Pathway.* Once the Executive Officer has approved the initial demonstrations specified in section 95484(c~~d~~)(2)(A) through (C), the regulated party does not need to resubmit the demonstrations for Executive Officer approval in any subsequent year, unless there is a material change to any of the information submitted under section 95484(c~~d~~)(2)(A) through (C).

“Material change” means any change to the initially submitted information involving a change in the basic mode of transport for the fuel. For example, if an approved pathway using rail transport is changed to add to or replace the rail with truck or ship transport, that change would be deemed a material change.

If there is a material change to an approved physical pathway, the regulated party must notify the Executive Officer in writing within 30 business days after the material change has occurred, and the approved physical pathway shall become invalid 30 business days after the material change has occurred. A regulated party that wishes to generate credits after an approved physical pathway has become invalid must submit for Executive Officer approval a new initial demonstration~~s~~, pursuant to section 95484(c~~d~~)(2)(A) through (C), which includes the material change(s) to the physical pathway.

(E) *Submittal and Review of and Final Action on Submitted Demonstrations*

1. The regulated party may not receive credit for any fuel or blendstock until the Executive Officer has approved the regulated party's submitted physical-pathway demonstration pursuant to section 95484(c~~d~~)(2)(A) through (C). Upon receiving Executive Officer approval of a physical pathway, the regulated party may claim LCFS credits based on that pathway that are calculated retroactive to the date when the regulated party's use of the pathway began but no earlier than January 1, 2011.

2. Within 15 business days of receipt of a physical pathway demonstration, the Executive Officer shall determine if the physical pathway demonstration is complete and notify the regulated party accordingly. If incomplete, the Executive Officer shall notify the regulated party and identify the information needed to complete the demonstrations identified in section 95484(c~~d~~)(2)(A) through (C). Once the Executive Officer deems the demonstrations to be complete, the Executive Officer shall, within 15 business days, take final action to either approve or disapprove a physical pathway demonstration and notify the regulated party of the final action.

(3) *Data Verification.* All data and calculations submitted by a regulated party for demonstrating compliance or claiming credit are subject to verification by the Executive Officer or a third party approved by the Executive Officer.

(4) *Access To Facility And Data.* Pursuant to H&S section 41510, if necessary under the circumstances, after obtaining a warrant, the Executive Officer has the right of entry to any premises owned, operated, used, leased, or rented by an owner or operator of a facility in order to inspect and copy records relevant to the determination of compliance.

(5) The Executive Officer shall post on the ARB's website at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm the names and contact information for each regulated party and non-regulated party fuel producer that has obtained Executive Officer approval of its physical pathway demonstration; the transportation fuels and blendstocks covered by such Executive Officer approval; and details of the approved physical pathways disclosed in accordance with 17 CCR §§ 91000 – 91022 and the California Public Records Act (Government Code section 6250 et seq.).

(~~e~~d) *Violations and Penalties.*

(1) Pursuant to H&S section 38580 (part of the California Global Warming Solutions Act of 2006), any violation of the provisions of the LCFS regulation (title 17, CCR, § 95480 et seq.) may be enjoined pursuant to H&S section 41513, and the violation is subject to those penalties set forth in Article 3 (commencing with § 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with § 43025) of Part 5 of, Division 26.

(2) Pursuant to H&S section 38580, any violation of the provisions of the LCFS regulation shall be deemed to result in an emission of an air contaminant for the purposes of the penalty provisions of Article 3 (commencing with § 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with § 43025) of Part 5 of, Division 26.

(3) Any violation of the provisions of the LCFS regulation shall be subject to all other penalties and remedies permitted under State law.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95485. LCFS Credits and Deficits.

(a) *Calculation of Credits and Deficits Generated.* A regulated party must calculate the amount of credits and deficits generated in a compliance period for an LCFS fuel using the methods specified below in section 95485(a)(1) through (3). The total credits and deficits generated are used in determining the overall credit balance for a compliance period, pursuant to section 95488(a) ~~95484(b)~~. All credits and deficits are denominated in units of metric tons (MT) of carbon dioxide equivalent.

(1) All LCFS fuel quantities used for credit calculation must be in energy units of megajoules (MJ).

Fuel quantities denominated in other units, such as those shown in Table 4, must be converted to MJ by multiplying by the corresponding energy density[1]:

Table 4. Energy Densities of LCFS Fuels and Blendstocks.

Fuel (units)	Energy Density
CARBOB (gal)	119.53 (MJ/gal)
CaRFG (gal)	115.63 (MJ/gal)
Diesel fuel (gal)	134.47 (MJ/gal)
CNG (scf)	0.98 (MJ/scf)
LNG (gal)	78.83 (MJ/gal)
Electricity (KWh)	3.60 (MJ/KWh)
Hydrogen (kg)	120.00 (MJ/kg)
Anhydrous Ethanol (gal)	80.53 (MJ/gal)
Neat Biomass-based diesel (gal)	126.13 (MJ/gal)

(2) The total credits and deficits generated by a regulated party in a compliance period must be calculated as follows:

$$Credits^{Gen}(MT) = \sum_{i}^{n} Credits_i^{gasoline} + \sum_{i}^{n} Credits_i^{diesel}$$

$$Deficits^{Gen}(MT) = \sum_{i}^{n} Deficits_i^{gasoline} + \sum_{i}^{n} Deficits_i^{diesel}$$

where:

[1] Energy density factors are based on the lower heating values of fuels in CA-GREET using BTU to MJ conversion of 1055 J/Btu.

$Credits^{Gen}$ represents the total credits (a zero or positive value), in units of metric tons ("MT"), for all fuels and blendstocks determined from the credits generated under either or both of the gasoline and diesel fuel average carbon intensity requirements;

$Deficits^{Gen}$ represents the total deficits (a negative value), in units of metric tons ("MT"), for all fuels and blendstocks determined from the deficits generated under either or both of the gasoline and diesel fuel average carbon intensity requirements;

i is the finished fuel or blendstock index; and

n is the total number of finished fuels and blendstocks provided by a regulated party in a compliance period.

(3) LCFS credits or deficits for each fuel or blendstock supplied by a regulated party must be calculated according to the following equations:

(A) $$\boxed{Credits_i^{XD} \;/\; Deficits_i^{XD}(MT) = \left(CI_{s\tan dard}^{XD} - CI_{reported}^{XD}\right) \times E_{displaced}^{XD} \times C}$$

where:

$Credits_i^{XD} / Deficits_i^{XD}$ *(MT)* is either the amount of LCFS credits generated (a zero or positive value), or deficits incurred (a negative value), in metric tons, by a fuel or blendstock under the average carbon intensity requirement for gasoline (*XD*="gasoline") or diesel (*XD*="diesel");

$CI_{s\tan dard}^{XD}$ is the average carbon intensity requirement of either gasoline (*XD*= "gasoline") or diesel fuel (*XD*= "diesel") for a given year as provided in section 95482 (b) and (c), respectively;

$CI_{reported}^{XD}$ is the adjusted carbon intensity value of a fuel or blendstock, in gCO2E/MJ, calculated pursuant to section 95485(a)(3)(B);

$E_{displaced}^{XD}$ is the total amount of gasoline (*XD*="gasoline") or diesel (*XD*="diesel") fuel energy displaced, in MJ, by the use of an alternative fuel, calculated pursuant to section 95485(a)(3)(C); and

C is a factor used to convert credits to units of metric tons from gCO2E and has the value of:

$$C = 1.0x10^{-6}\frac{(MT)}{(gCO_2E)}$$

(B) $$CI^{XD}_{reported} = \frac{CI_i}{EER^{XD}}$$

where:

CI_i is the carbon intensity of the fuel or blendstock, measured in gCO2E/MJ, determined by a California-modified GREET pathway or a custom pathway and incorporates a land use modifier (if applicable); and

EER^{XD} is the dimensionless Energy Economy Ratio (EER) relative to gasoline (*XD*="gasoline") or diesel fuel (*XD*= "diesel") as listed in Table 5. For a vehicle-fuel combination not listed in Table 5, EER^{XD}=1 must be used.

(C) $$E^{XD}_{displaced} = E_i \times EER^{XD}$$

where:

E_i is the energy of the fuel or blendstock, in MJ, determined from the energy density conversion factors in Table 4.

Table 5. EER Values for Fuels Used in Light- and Medium-Duty, and Heavy-Duty Applications.

Light/Medium-Duty Applications (Fuels used as gasoline replacement)		**Heavy-Duty/Off-Road Applications (Fuels used as diesel replacement)**	
Fuel/Vehicle Combination	**EER Values Relative to Gasoline**	**Fuel/Vehicle Combination**	**EER Values Relative to Diesel**
Gasoline (incl. E6 and E10) or E85 (and other ethanol blends)	1.0	Diesel fuel or Biomass-based diesel blends	1.0
		CNG or LNG (Spark-Ignition Engines)	0.9
CNG / ICEV	1.0	CNG or LNG (Compression-Ignition Engines)	1.0
Electricity / BEV, or PHEV	~~3.0~~ 3.4	Electricity / BEV, or PHEV*	2.7
H2 / FCV	~~2.3~~ 2.5	H2 / FCV	1.9

*BEV = battery electric vehicle, PHEV= plug-in hybrid electric vehicle, FCV = fuel cell vehicle, ICEV = internal combustion engine vehicle.

(b) *Credit Generation Frequency.* Beginning 2011 and every year afterwards, a regulated party may generate credits quarterly.

(c) *Credit Acquisition, Banking, Borrowing, and Trading.*

(1) A regulated party may:

(A) retain LCFS credits without expiration for use within the LCFS market;

(B) acquire or transfer LCFS credits. A third-party entity, which is not a regulated party or acting on behalf of a regulated party, may not purchase, sell, or trade LCFS credits, except as otherwise specified in (C) below; and

(C) export credits for compliance with other greenhouse gas reduction initiatives including, but not limited to, programs established pursuant to AB 32 (Nunez, Stats. 2006, ch. 488), subject to the authorities and requirements of those programs.

(2) A regulated party may not:

(A) use credits in the LCFS program that are generated outside the LCFS program, including, but not limited to, credits generated in other AB 32 programs.

(B) borrow or use credits from anticipated future carbon intensity reductions.

(C) generate LCFS credits from fuels exempted from the LCFS under section 95480.1(d) or are otherwise not one of the transportation fuels specified in section 95480.1(a).

(d) *Nature of Credits.* LCFS credits shall not constitute instruments, securities, or any other form of property.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95486. Determination of Carbon Intensity Values.

(a) *Selection of Method.*

(1) A regulated party for CARBOB, gasoline, or diesel fuel must use Method 1, as set forth in section 95486(b)(2)(A), to determine the carbon intensity of each fuel or blendstock for which it is the regulated party.

(2) A regulated party for any other fuel or blendstock must use Method 1, as set forth in section 95486(b)(2)(B), to determine the carbon intensity of each ~~fuel for~~ of the regulated party's fuels, unless the regulated party is approved for using either Method 2A or Method 2B, as provided in section 95486(c) or (d). A regulated party may use Method 1 to determine the carbon intensity of each fuel he or she sells in California if the Carbon Intensity Lookup Table contains fuel pathways that closely correspond to the regulated party's fuel pathways. A regulated party's pathway corresponds closely with a Lookup Table pathway when it is consistent with Lookup Table pathway in the following areas:

(A) Feedstocks used to produce the fuel.

(B) Fuel and feedstock production technology.

(C) Geographic regions in which feedstocks and finished fuel are produced.

(D) The modes used to transport feedstocks and finished fuel and the transport distances involved.

(E) The types and amounts of thermal and electrical energy consumed in both feedstock and finished fuel production. This applies both to the energy consumed in the production process, but also to the upstream energy consumed (e.g., fuels used to generate electricity; energy consumed to produce natural gas, etc.).

(F) The CI of the regulated party's product must be lower than or equal to the Lookup Table pathway CI. If the Executive Officer determines that the regulated party's product has an actual CI that is likely to be higher than the Lookup Table pathway CI, the regulated party shall prepare a Method 2B application for a pathway-specific CI.

(3) A regulated party's choice of carbon intensity value under Method 1 in either (a)(1) or (a)(2) above is subject in all cases to Executive Officer approval, as specified in this provision.

(A) If the Executive Officer has reason to believe that the regulated party's choice is not the value that most closely corresponds to its fuel or blendstock, the Executive Officer shall choose a carbon intensity value, in the Carbon Intensity Lookup Tables for the fuel or blendstock, which the Executive Officer determines is the one that most closely corresponds to the pathway for that fuel or blendstock.

(B) If the Executive Officer has reason to believe that the Carbon Intensity Lookup Table does not contain a fuel pathway that closely corresponds with the regulated party's fuel pathway, as specified in 95486(a)(2), the regulated party will not be allowed to use Method 1, and the Executive Officer may permit the regulated party to use a carbon intensity value pursuant to subsection (5) below for determining the regulated party's fuel carbon intensity.

(C) The Executive Officer shall provide the rationale for his/her determination to the regulated party in writing within 10 business days of the determination. The regulated party shall be responsible for reconciling any deficits, in accordance with section 95485, that were incurred as a result of its initial choice of carbon intensity values. In determining whether a carbon intensity value that is different than the one chosen by the regulated party is more appropriate, the Executive Officer may consider any information submitted by the regulated party in support of its choice of carbon intensity value.

(4) A regulated party who has purchased ethanol or biomass-based diesel but is unable to determine the carbon intensity of that fuel may petition the Executive Officer to use a default carbon intensity value. The Executive Officer may grant a regulated party permission to use a default value only if the regulated party demonstrates that the use of Methods 1 and 2 are not available for the volume of fuel and that the fuel cannot be sold outside of California. The term "unable to be determined" is defined, for purposes of this provision, as follows:

(A) The production facility cannot be identified, or

(B) The production facility is known, but it has neither been registered through the LCFS Biofuel Producer Registration process nor received a pathway carbon intensity through the Method 2A or 2B process.

(5) Pursuant to Paragraph (4) above, the Executive Officer may grant regulated parties permission to use the following carbon intensities for ethanol and biomass-based diesel, respectively:

(A) For ethanol, the Midwest Average ethanol carbon intensity of 99.40 gCO_2e/MJ from Table 6 in Section 95486(b), and

(B) For biomass-based diesel, the ULSD carbon intensity value of 96.36 from Table 7 in Section 95486(b).

(b) *Method 1 – ARB Lookup Table.*

(1) To generate carbon intensity values, ARB uses the California-modified GREET (CA-GREET) model ~~(~~version 1.8b~~,~~ (February 2009, updated December 2009~~)~~), which is incorporated herein by reference, and a land-use change (LUC) modifier (when applicable). The CA-GREET model is available for downloading on ARB's website at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.

The Carbon-Intensity Lookup Tables, shown below, specify the carbon intensity values for the enumerated fuel pathways that are described in the following supporting documents, all of which are incorporated herein by reference:

(A) Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1), "Detailed California-Modified GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California;"

(A.1) Supplement (October 28, 2011) to Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1), "Detailed California-Modified GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California;"

(B) Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1), "Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG);"

(B.1) Supplement (October 28, 2011) to Stationary Source Division, Air Resources Board (February 28, 2009, v.2.1), "Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG);"

(C) Stationary Source Division, Air Resources Board (February 28, 2009, v.2.1), "Detailed California-Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California;"

(C.1) Supplement October 28, 2011) to Stationary Source Division, Air Resources Board (February 28, 2009, v.2.1), "Detailed California-

Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California;”

(D) Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1), “Detailed California-Modified GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California;”

(E) Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1), “Detailed California-Modified GREET Pathway for Corn Ethanol;”

(F) Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1), “Detailed California-Modified GREET Pathway for Brazilian Sugarcane Ethanol;”

(G) Stationary Source Division, Air Resources Board (February 28, 2009, v.2.1), “Detailed California-Modified GREET Pathway for Compressed Natural Gas (CNG) from North American Natural Gas;”

(H) Stationary Source Division, Air Resources Board (February 28, 2009, v.2.1), “Detailed California-Modified GREET Pathway for Compressed Natural Gas (CNG) from Landfill Gas;”

(I) Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1), “Detailed California-Modified GREET Pathway for California Average and Marginal Electricity;”

(J) Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1), “Detailed California-Modified GREET Pathway for Compressed Gaseous Hydrogen from North American Natural Gas;”

(K) Stationary Source Division, Air Resources Board (September 23, 2009, v.2.0), “Detailed California-Modified GREET Pathways for Liquefied Natural Gas (LNG) from North American and Remote Natural Gas Sources;”

(L) Stationary Source Division, Air Resources Board (September 23, 2009, v.2.0), “Detailed California-Modified GREET Pathway for Liquefied Natural Gas (LNG) from Landfill Gas (LFG);”

(M) Stationary Source Division, Air Resources Board (July 20, 2009, v.1.0), “Detailed California-Modified GREET Pathway for Compressed Natural Gas (CNG) from Dairy Digester Biogas;”

(N) Stationary Source Division, Air Resources Board (September 23, 2009, v.2.0), “Detailed California-Modified GREET Pathway for Liquefied Natural Gas (LNG) from Dairy Digester Biogas;”

(O) Stationary Source Division, Air Resources Board (September 23, 2009, v.2.0), “Detailed California-Modified GREET Pathway for Biodiesel from Used Cooking Oil;”

(P) Stationary Source Division, Air Resources Board (September 23, 2009, v.2.0), “Detailed California-Modified GREET Pathway for Co-Processed Renewable Diesel from Tallow (U.S. Sourced);”

(Q) Stationary Source Division, Air Resources Board (September 23, 2009, v.2.3), “Detailed California-Modified GREET Pathways for Brazilian Sugarcane Ethanol: Average Brazilian Ethanol, With Mechanized Harvesting and Electricity Co-product Credit, With Electricity Co-product Credit;”

(R) Stationary Source Division, Air Resources Board (December 14, 2009, v.3.0), “Detailed California-Modified GREET Pathway for Biodiesel from Midwest Soybeans; and

(S) Stationary Source Division, Air Resources Board (December 14, 2009, v.3.0), “Detailed California-Modified GREET Pathway for Renewable Diesel from Midwest Soybeans.

Table 6. Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline.

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ) Direct Emissions	Land Use or Other Indirect Effect	Total
CARBOB ~~Gasoline~~	CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies	97.51 ~~95.86~~	0	97.51 ~~95.86~~
	Baseline Crude Average – based on production and transport of the crude oil used as petroleum feedstock for California refineries during the baseline calendar year, 2009	9.72	0	9.72
	Annual Crude Average – based on production and transport of the crude oil used as petroleum feedstock for California refineries during a specified calendar year*	See section 95486(b)(2)(A)1.	0	See section 95486(b)(2)(A)1.
Ethanol from Corn	Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	69.40	30	99.40
	California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG	65.66	30	95.66
	California; Dry Mill; Wet DGS; NG	50.70	30	80.70
	Midwest; Dry Mill; Dry DGS, NG	68.40	30	98.40
	Midwest; Wet Mill, 60% NG, 40% coal	75.10	30	105.10
	Midwest; Wet Mill, 100% NG	64.52	30	94.52
	Midwest; Wet Mill, 100% coal	90.99	30	120.99
	Midwest; Dry Mill; Wet DGS	60.10	30	90.10
	California; Dry Mill; Dry DGS, NG	58.90	30	88.90
	Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass	63.60	30	93.60
	Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass	56.80	30	86.80
	California; Dry Mill; Dry DGS; 80% NG; 20% Biomass	54.20	30	84.20
	California; Dry Mill; Wet DGS; 80% NG; 20% Biomass	47.44	30	77.44
Ethanol from Sugarcane	Brazilian sugarcane using average production processes	27.40	46	73.40
	Brazilian sugarcane with average production process, mechanized harvesting and electricity co-product credit	12.40	46	58.40
	Brazilian sugarcane with average production process and electricity co-product credit	20.40	46	66.40

Compressed Natural Gas	California NG via pipeline; compressed in CA	67.70	0	67.70
	North American NG delivered via pipeline; compressed in CA	68.00	0	68.00
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA	11.26	0	11.26
	Dairy Digester Biogas to CNG	13.45	0	13.45
Liquefied Natural Gas	North American NG delivered via pipeline; liquefied in CA using liquefaction with 80% efficiency	83.13	0	83.13
	North American NG delivered via pipeline; liquefied in CA using liquefaction with 90% efficiency	72.38	0	72.38
	Overseas-sourced LNG delivered as LNG to Baja; re-gasified then re-liquefied in CA using liquefaction with 80% efficiency	93.37	0	93.37
	Overseas-sourced LNG delivered as LNG to CA; re-gasified then re-liquefied in CA using liquefaction with 90% efficiency	82.62	0	82.62
	Overseas-sourced LNG delivered as LNG to CA; no re-gasification or re-liquefaction in CA	77.50	0	77.50
	Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 80% efficiency	26.31	0	26.31
	Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 90% efficiency	15.56	0	15.56
	Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 80% efficiency	28.53	0	28.53
	Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 90% efficiency	17.78	0	17.78
Electricity	California average electricity mix	124.10	0	124.10
	California marginal electricity mix of natural gas and renewable energy sources	104.71	0	104.71
Hydrogen	Compressed H_2 from central reforming of NG (includes liquefaction and re-gasification steps)	142.20	0	142.20
	Liquid H_2 from central reforming of NG	133.00	0	133.00
	Compressed H_2 from central reforming of NG (no liquefaction and re-gasification steps)	98.80	0	98.80
	Compressed H_2 from on-site reforming of NG	98.30	0	98.30
	Compressed H_2 from on-site reforming with renewable feedstocks	76.10	0	76.10

* The annual crude Average CI value will be first calculated for calendar year 2012 and subsequently updated annually using data for crude oil supplied to California refineries during the specified calendar year.

Table 7. Carbon Intensity Lookup Table for Diesel and Fuels that Substitute for Diesel.

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
		Direct Emissions	Land Use or Other Indirect Effect	Total
Diesel	ULSD – based on the average crude oil delivered to California refineries and average California refinery efficiencies	96.36~~94.71~~	0	96.36~~94.71~~
	Baseline Crude Average – based on production and transport of the crude oil used as petroleum feedstock for California refineries during the baseline calendar year, 2009	9.72	0	9.72
	Annual Crude Average – based on production and transport of the crude oil used as petroleum feedstock for California refineries during a specified calendar year**	See section 95486(b)(2)(A)1.	0	See section 95486(b)(2)(A)1.
Biodiesel	Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is required	15.84	0	15.84
	Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is not required	11.76	0	11.76
	Conversion of Midwest soybeans to biodiesel (fatty acid methyl esters -FAME)	21.25	62	83.25
Renewable Diesel	Conversion of tallow to renewable diesel using higher energy use for rendering	39.33	0	39.33
	Conversion of tallow to renewable diesel using lower energy use for rendering	19.65	0	19.65
	Conversion of Midwest soybeans to renewable diesel	20.16	62	82.16
Compressed Natural Gas	California NG via pipeline; compressed in CA	67.70	0	67.70
	North American NG delivered via pipeline; compressed in CA	68.00	0	68.00
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA	11.26	0	11.26
	Dairy Digester Biogas to CNG	13.45	0	13.45
Liquefied Natural Gas	North American NG delivered via pipeline; liquefied in CA using liquefaction with 80% efficiency	83.13	0	83.13
	North American NG delivered via pipeline; liquefied in CA using liquefaction with 90% efficiency	72.38	0	72.38
	Overseas-sourced LNG delivered as LNG to Baja;	93.37	0	93.37

	re-gasified then re-liquefied in CA using liquefaction with 80% efficiency			
	Overseas-sourced LNG delivered as LNG to CA; re-gasified then re-liquefied in CA using liquefaction with 90% efficiency	82.62	0	82.62
	Overseas-sourced LNG delivered as LNG to CA; no re-gasification or re-liquefaction in CA	77.50	0	77.50
	Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 80% efficiency	26.31	0	26.31
	Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 90% efficiency	15.56	0	15.56
	Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 80% efficiency	28.53	0	28.53
	Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 90% efficiency	17.78	0	17.78
Electricity	California average electricity mix	124.10	0	124.10
	California marginal electricity mix of natural gas and renewable energy sources	104.71	0	104. 71
Hydrogen	Compressed H_2 from central reforming of NG (includes liquefaction and re-gasification steps)	142.20	0	142.20
	Liquid H_2 from central reforming of NG	133.00	0	133.00
	Compressed H_2 from central reforming of NG (no liquefaction and re-gasification steps)	98.80	0	98.80
	Compressed H_2 from on-site reforming of NG	98.30	0	98.30
	Compressed H_2 from on-site reforming with renewable feedstocks	76.10	0	76.10

<u>** The annual crude Average CI value will be first calculated for calendar year 2012 and subsequently updated annually using data for crude oil supplied to California refineries during the specified calendar year.</u>

(2) *Lookup-Table Carbon-Intensity Values.*

(A) *For CARBOB and Diesel Fuel.*

Deficit calculations to be used for a regulated party's CARBOB or diesel fuel are specified in section 95486(b)(2)(A)1. Requirements for adding incremental emission increases associated with an increase in the carbon intensity of crude oil to a regulated party's compliance obligation are specified in section 95486(b)(2)(A)2. The credit calculation for CARBOB or diesel derived from petroleum feedstock which is produced using innovative methods such as carbon capture and sequestration (CCS) is specified in section 95486(b)(2)(A)3.

1. *Deficit Calculation for CARBOB or Diesel Fuel.*

A regulated party for CARBOB or diesel fuel must calculate separately the base deficit and incremental deficit for each fuel or blendstock derived from petroleum feedstock as specified in this provision.

Base Deficit Calculation

$$Deficits^{XD}_{Base}\ (MT) = (CI^{XD}_{Standard} - CI^{XD}_{BaselineAvg}) \times E^{XD} \times C$$

Incremental Deficit Calculation to Mitigate Increases in the Carbon-Intensity of Crude Oil

$$If\ \ CI^{XD}_{20XXCrudeAvg} > CI^{XD}_{BaselineCrudeAvg}\ \ then:$$

$$Deficits^{XD}_{Incremental\ 20XX} =$$

$$(CI^{XD}_{BaselineCrudeAvg} - CI^{XD}_{20XXCrudeAvg}) \times E^{XD} \times C$$

$$If\ \ CI^{XD}_{20XXCrudeAvg} \leq CI^{XD}_{BaselineCrudeAvg}\ \ then:$$

$$Deficits^{XD}_{Incremental\ 20XX} = 0$$

where,

$Deficits^{XD}_{Base}(MT)$ and $Deficits^{XD}_{Incremental20XX}$ mean the amount of LCFS deficits incurred (a negative value), in metric tons, by the volume of CARBOB and diesel that is derived from petroleum feedstock and is either produced in or imported into California during a specific calendar year;

$CI^{XD}_{Standard}$ has the same meaning as specified in section 95485(a)(3)(A);

$CI^{XD}_{BaselineAvg}$ is the average carbon-intensity value of CARBOB or diesel, in gCO2E/MJ, that is derived from petroleum feedstock and is either produced in or imported into California during the baseline calendar year, 2009. For purposes of this provision, $CI^{XD}_{BaselineAvg}$ for CARBOB (XD = "CARBOB") and diesel fuel (XD = "diesel") are the Baseline Average carbon intensity values for CARBOB and diesel (ULSD) set forth in the Carbon Intensity Lookup Table. The Baseline Average carbon intensity values for CARBOB and diesel (ULSD) are calculated using data for crude oil supplied to California refineries during the baseline calendar year, 2009.

$CI^{XD}_{BaselineCrudeAvg}$ is the California average crude oil carbon-intensity value, in gCO2E/MJ, attributed to the production and transport of the crude oil used as petroleum feedstock for California refineries during the baseline calendar year, 2009. For purposes of this provision, $CI^{XD}_{BaselineCrudeAvg}$ for CARBOB (XD = "CARBOB") and diesel fuel (XD = "diesel") is the Baseline Crude Average carbon intensity value set forth in the Lookup Table. The Baseline Crude Average carbon intensity value is calculated using data for crude oil supplied to California refineries during the baseline calendar year, 2009.

$CI^{XD}_{20XXCrudeAvg}$ is the California average crude oil carbon-intensity value, in gCO2E/MJ, attributed to the production and transport of the crude oil used as petroleum feedstock for California refineries in a specific calendar year. For purposes of this provision, $CI^{XD}_{20XXCrudeAvg}$ for CARBOB (XD = "CARBOB") and diesel fuel (XD = "diesel") is the Annual Crude Average carbon intensity value set forth in the Lookup Table. The Annual Crude Average carbon-intensity value will be first calculated for calendar year 2012 and subsequently will be updated annually using data for crude oil supplied to California refineries during the specified calendar year. Crude oil used to produce CARBOB or diesel for which a credit is claimed in a calendar year pursuant to section 95486(b)(2)(A)3 will be included in the Annual Crude Average carbon-intensity calculations for that year based on the carbon intensity of the crude oil prior to calculation of any innovative credits allowed pursuant to section 95486(b)(2)(A)3.

E^{XD} is the amount of fuel energy, in MJ, from CARBOB (XD = "CARBOB") or diesel (XD = "diesel"), determined from the energy density conversion factors in Table 4, either produced in California or imported into California during a specific calendar year.

C has the same meaning as specified in section 95485(a)(3)(A).

2. *Addition of Incremental Deficits that Result from Increases in the Carbon-Intensity of Crude Oil to a Regulated Party's Compliance Obligation.*

a. Incremental deficits for CARBOB or diesel fuel that result from increases in the carbon-intensity of crude oil will be calculated and added to each affected regulated party's compliance obligation for the compliance period in which the $Deficits^{XD}_{Incremental20XX}$ become effective, which will be the year following the year in which the incremental deficit was established and added to the Lookup Table.

b. Incremental deficits for CARBOB or diesel fuel for each regulated party will be based upon the amount of CARBOB and Diesel fuel supplied by the regulated party in each compliance period for which the $Deficits^{XD}_{Incremental20XX}$ are effective.

3. A regulated party may receive credit for fuel or blendstock derived from petroleum feedstock which has been produced using innovative methods such as carbon capture and sequestration or other methods approved by the Executive Officer. Implementation of the innovative method must have occurred during or after the year 2010 and must result in a reduction in carbon intensity for crude oil recovery (well to refinery entrance gate) of 5.00 gCO2E/MJ or greater. Using the Method 2A process as set forth in section 95486(c), the regulated party must submit to ARB carbon intensity values for petroleum feedstock recovered both with and without implementation of the innovative method. Credits for CARBOB, gasoline, or diesel derived from this petroleum feedstock must be calculated as specified below:

$$Credits^{XD}_{Innov}(MT) = (CI^{XD}_{Without} - CI^{XD}_{With})_{Innov} \times E^{XD}_{Innov} \times C$$

where,

$Credits^{XD}_{Innov}(MT)$ mean the amount of LCFS credits generated (a positive value), in metric tons, by the volume of a fuel or blendstock produced in California and derived wholly from petroleum feedstock which uses the innovative production method;

CI^{XD}_{With} means the carbon intensity value, in gCO2E/MJ, of the petroleum feedstock produced with the innovative method;

$CI^{XD}_{Without}$ means the carbon intensity value, in gCO2E/MJ, of the petroleum feedstock produced using a similar process but without the innovative method;

E^{XD}_{Innov} is the amount of fuel energy, in MJ, from CARBOB (XD = "CARBOB") or diesel (XD = "diesel"), determined from the energy density conversion factors in Table 4, produced in California and derived wholly from petroleum feedstock produced with the innovative method;

C has the same meaning as specified in section 95485(a)(3)(A).

~~For purposes of this section 95486(b)(2)(A), "2006 California baseline crude mix" means the total pool of crude oil supplied to California refiners in 2006; "included in the 2006 California baseline crude mix" means the crude oil constituted at least 2.0% of the 2006 California baseline crude mix, by volume, as shown by California Energy Commission records for 2006; and "high carbon-intensity crude oil" means any crude oil that has a total production and transport carbon-intensity value greater than 15.00 grams CO2e/MJ.~~

~~The carbon intensity for a regulated party's CARBOB, gasoline or a diesel fuel is determined as specified in section 95486(b)(2)(A)1. or 2. below, whichever applies:~~

~~1.~~ ~~*For CARBOB, Gasoline or Diesel Fuel Derived from Crude Oil That Is Either Included in the 2006 California Baseline Crude Mix or Is Not a High Carbon Intensity Crude Oil.*~~

~~If all of a regulated party's CARBOB, gasoline or diesel fuel is derived from crude oil that is either:~~

~~a.~~ ~~included in the 2006 California baseline crude mix, or~~

~~b.~~ ~~not a high carbon-intensity crude oil,~~

~~the regulated party must use the average carbon intensity value shown in the Carbon Intensity Lookup Table for CARBOB, gasoline or diesel fuel.~~

~~2.~~ ~~*For All Other CARBOB, Gasoline or Diesel Fuel, Including Those Derived from High Carbon-Intensity Crude Oil (HCICO).*~~

~~Except as set forth in this provision, if any portion of a regulated party's CARBOB, gasoline, or diesel fuel does not fall within section 95486(b)(2)(A)1. above (including those derived from high carbon-~~

~~intensity crude oil), the regulated party must calculate the deficits for CARBOB, gasoline, or diesel fuel, derived wholly or in part from crude oil subject to this provision, using the deficit calculation methodology and the process for determining the carbon intensity value described in paragraphs a. and b., respectively, below:~~

~~a.~~ ~~*Deficit Calculation When HCICO Is Used.*~~

~~i.~~ ~~*Calculation Methodology*. For purposes of this section, a regulated party for CARBOB, gasoline or diesel fuel, derived wholly or in part from HCICO feedstock, must calculate separately the base deficit and incremental deficit for each fuel or blendstock, as specified in this provision. The base deficit must be calculated for the entire volume of fuel or blendstock derived from the mix of HCICO and all other crude, and the incremental deficit must be calculated only for the volume of fuel or blendstock derived from the HCICO, as follows:~~

$$Deficits^{XD}_{Base_i}(MT) = (CI^{XD}_{Standard_i} - CI^{XD}_{Avg_i}) \times E^{XD}_{Total_i} \times C$$

~~and~~

$$Deficits^{XD}_{Incremental_i}(MT) = (CI^{XD}_{Avg_i} - CI^{XD}_{HCICO_i}) \times E^{XD}_{HCICO_i} \times C$$

~~where,~~

~~*i* is the finished fuel or blendstock index;~~

$Deficits^{XD}_{Base}$ ~~*(MT)* means the amount of LCFS deficits incurred (a negative value), in metric tons, by the volume of gasoline, CARBOB, or diesel fuel that is derived from all petroleum feedstock, including HCICO, produced in or imported into California during a specific calendar year;~~

$Deficits^{XD}_{Incremental}$ ~~*(MT)* means the amount of LCFS deficits incurred (a negative value), in metric tons, by the volume of a fuel or blendstock that is derived wholly from HCICO feedstock produced in or imported into California during a specific calendar year;~~

~~$CI_{Standard}^{XD}$ has the same meaning as specified in section 95485(a)(3)(A);~~

~~CI_{Avg}^{XD} is the adjusted average carbon-intensity value of a fuel or blendstock, in gCO2E/MJ, derived from all petroleum feedstock, including HCICO, produced in or imported into California during a specific calendar year, where the carbon intensity of the fuel or blendstock is adjusted by dividing it with the EER as described in section 95485(a)(3)(B). For purposes of this provision, CI_{Avg}^{XD} for CARBOB (*XD* = "gasoline") and diesel fuel (*XD* = "diesel") is the total carbon intensity value for CARBOB and diesel (ULSD) set forth in the Carbon Intensity Lookup Table, respectively;~~

~~CI_{HCICO}^{XD} is the adjusted actual carbon-intensity value of a fuel or blendstock, in gCO2E/MJ, derived from HCICO feedstock produced in or imported into California during a specific calendar year, where the carbon intensity of the fuel or blendstock, as determined pursuant to paragraph ii. below, is adjusted by dividing it with the EER as described in section 95485(a)(3)(B);~~

~~E_{Total}^{XD} is the adjusted total amount of fuel energy, in MJ, from gasoline (*XD*="gasoline") or diesel (*XD*="diesel"), derived from all petroleum feedstock produced in or imported into California during a specific calendar year, where the total amount of fuel energy of the fuel is adjusted by multiplying it with the EER as described in section 95485(a)(3)(C). Where the petroleum feedstock is comprised entirely of HCICO, E_{Total}^{XD} equals E_{HCICO}^{XD};~~

~~E_{HCICO}^{XD} is the adjusted total amount of fuel energy, in MJ, from gasoline (*XD*="gasoline") or diesel (*XD*="diesel"), derived from HCICO feedstock produced in or imported into California during a specific calendar year, where the total amount of fuel energy of the fuel is adjusted by multiplying it with the EER as described in section 95485(a)(3)(C); and~~

~~*C* has the same meaning as specified in section 95485(a)(3)(A).~~

~~ii. *Determination of Carbon Intensity Value for HCICO-derived Products,*~~ $\cancel{CI^{XD}_{HCICO}}$~~.~~

~~A regulated party subject to section 95486(b)(2)(A) must determine the carbon intensity value for its CARBOB, gasoline or diesel fuel using any of the following that applies, subject to Executive Officer approval as specified in section 95485(a)(2) or as otherwise specified.~~

~~I. The carbon intensity value shown in the Carbon Intensity Lookup Table corresponding to the HCICO's pathway; or~~

~~II. Except as provided in paragraph III. below, if there is no carbon intensity value shown in the Carbon Intensity Lookup Table corresponding to the HCICO's pathway, the regulated party must propose a new pathway for its HCICO and obtain approval from the Executive Officer for the resulting pathway's carbon intensity pursuant to Method 2B as set forth in section 95486(d) and (f); or~~

~~III. The regulated party may, upon written Executive Officer approval pursuant to section 95486(f), use the average carbon intensity value in the Carbon Intensity Lookup Table for CARBOB, gasoline or diesel fuel, provided the GHG emissions from the fuel's crude production and transport steps are subject to control measures, such as carbon capture-and-sequestration (CCS) or other methods, which reduce the crude oil's production and transport carbon-intensity value to 15.00 grams CO2e/MJ or less, as determined by the Executive Officer.~~

(B) *For All Other Fuels and Blendstocks.*

Except as provided in section 95486(c) and (d), for each of a regulated party's fuels, the regulated party must <u>determine whether the Carbon Intensity Lookup Table contains one or more pathways that closely correspond to the regulated party's fuel pathways. This determination shall be made as set forth in 95486 (a)(2). If the regulated party determines that the Carbon Intensity Lookup Table contains one or more pathways that closely correspond to the regulated party's pathways, the regulated party shall</u> use the carbon intensity value in <u>the</u> Lookup Table that most closely corresponds to the production process used to produce the regulated party's fuel. The <u>determination that the Carbon Intensity Lookup Table contains one or more pathways that closely correspond to the regulated party's pathways, and the ultimate selection of a</u> Lookup Table carbon intensity value selected by the regulated party is subject to approval by the Executive Officer <u>as set forth in Section 95486 (a)(3).</u>

[Note: For example, if one of the regulated party's fuels is compressed natural gas (CNG) used in a light-duty vehicle, and the CNG is derived from dairy digester biogas, the regulated party would use the total carbon intensity value in Carbon Intensity Lookup Table 6 (i.e., the last column in Lookup Table 6) corresponding to the applicable Fuel (compressed natural gas) and Pathway Description (Dairy Digester Biogas to CNG). The result in this example would be a total carbon intensity value of 13.45 gC02e/MJ.]

(c) *Method 2A – Customized Lookup Table Values (Modified Method 1).*

Under Method 2A, the regulated party may propose, for the Executive Officer's written approval pursuant to section 95486(f), modifications to one or more inputs to the CA-GREET model used to generate the carbon intensity values in the Method 1 Lookup Table.

For any of its transportation fuels subject to the LCFS regulation, a regulated party may propose the use of Method 2A to determine the fuel's carbon intensity, as provided in this section 95486(c). For each fuel subject to a proposed Method 2A, the regulated party must obtain written approval from the Executive Officer for its proposed Method 2A before the regulated party may use Method 2A for determining the carbon intensity of the fuel. The Executive Officer's written approval may include more than one of a regulated party's fuels under Method 2A.

The Executive Officer may not approve a proposed Method 2A unless the regulated party and its proposed Method 2A meet the scientific defensibility, "5-10" substantiality, and data submittal requirements specified in section 95486(e)(1) through (3) and the following requirements:

(1) The proposed modified CA-GREET inputs must accurately reflect the conditions specific to the regulated party's production and distribution process;

(2) The proposed Method 2A uses only the inputs that are already incorporated in CA-GREET and does not add any new inputs (e.g., refinery efficiency); and

(3) The regulated party must request the Executive Officer to conduct an analysis or modeling to determine the new pathway's impact on total carbon intensity due to indirect effects, including land-use changes, as the Executive Officer deems appropriate. The Executive Officer will use the GTAP Model (February 2009), which is incorporated by reference, or other model determined by the Executive Officer to be at least equivalent to the GTAP Model (February 2009).

(d) *Method 2B – New Pathway Generated by California-Modified GREET (v.1.8b).*

Under Method 2B, the regulated party proposes for the Executive Officer's written approval the generation of a new pathway using the CA-GREET as provided for in this provision. The Executive Officer's approval is subject to the requirements as specified in section 95486(f) and the following requirements:

(1) For purposes of this provision, "new pathway" means the proposed full fuel-cycle (well-to-wheel) pathway is not already in the ARB Lookup Table specified in section 95486(b)(1), as determined by the Executive Officer;

(2) The regulated party must demonstrate to the Executive Officer's satisfaction that the CA-GREET can be modified successfully to generate the proposed new pathway. If the Executive Officer determines that the CA-GREET model cannot successfully generate the proposed new pathway, the proponent-regulated party must use either Method 1 or Method 2A to determine its fuel's carbon intensity;

(3) The regulated party must identify all modified parameters for use in the CA-GREET for generating the new pathway;

(4) The CA-GREET inputs used to generate the new pathway must accurately reflect the conditions specific to the regulated party's production and marketing process; and

(5) The regulated party must request the Executive Officer to conduct an analysis or modeling to determine the new pathway's impact on total carbon intensity due to indirect effects, including land-use changes, as the Executive Officer deems appropriate. The Executive Officer will use the GTAP Model (February 2009), which is incorporated by reference, or other

model determined by the Executive Officer to be at least equivalent to the GTAP Model (February 2009).

(e) *Scientific Defensibility, Burden of Proof, Substantiality, and Data Submittal Requirements and Procedure for Approval of Method 2A or 2B.* For a proposed Method 2A or 2B to be approved by the Executive Officer, the regulated party must demonstrate that the method is both scientifically defensible and, for Method 2A, meets the substantiality requirement, as specified below:

(1) *Scientific Defensibility and Burden of Proof.* This requirement applies to both Method 2A and 2B. A regulated party that proposes to use Method 2A or 2B bears the sole burden of demonstrating to the Executive Officer's satisfaction, that the proposed method is scientifically defensible.

(A) For purposes of this regulation, "scientifically defensible" means the method has been demonstrated to the Executive Officer as being at least as valid and robust as Method 1 for calculating the fuel's carbon intensity.

(B) Proof that a proposed method is scientifically defensible may rely on, but is not limited to, publication of the proposed Method 2A or 2B in a major, well-established and peer-reviewed scientific journal (e.g., Science, Nature, Journal of the Air and Waste Management Association, Proceedings of the National Academies of Science).

(2) *"5-10" Substantiality Requirement.* This requirement applies only to a proposed use of Method 2A, as provided in section 95486(c). For each of its transportation fuels for which a regulated party is proposing to use Method 2A, the regulated party must demonstrate, to the Executive Officer's satisfaction, that the proposed Method 2A meets both of the following substantiality requirements:

(A) The source-to-tank carbon intensity for the fuel under the proposed Method 2A is at least 5.00 grams CO2-eq/MJ less than the source-to-tank carbon intensity for the fuel as calculated under Method 1. "Source-to-tank" means all the steps involved in the growing/extraction, production and transport of the fuel to California, but it does not include the carbon intensity due to the vehicle's use of the fuel; "source-to-tank" may also be referred to as "well-to-tank" or "field-to-tank."

(B) The regulated party can and expects to provide in California more than 10 million gasoline gallon equivalents per year (1,156 MJ) of the regulated fuel. This requirement applies to a transportation fuel only if the total amount of the fuel sold in California from all providers of that fuel exceeds 10 million gasoline gallon equivalents per year.

(3) *Data Submittal.* This requirement applies to both Method 2A and 2B. A regulated party proposing Method 2A or 2B for a fuel's carbon intensity value must meet all the following requirements:

(A) Submit to the Executive Officer all supporting data, calculations, and other documentation, including but not limited to, flow diagrams, flow rates, CA-GREET calculations, equipment description, maps, and other information that the Executive Officer determines is necessary to verify the proposed fuel pathway and how the carbon intensity value proposed for that pathway was derived;

(B) All relevant data, calculations, and other documentation in (A) above must be submitted electronically, such as via email or an online web-based interface, whenever possible;

(C) The regulated party must specifically identify all information submitted pursuant to this provision that is a trade secret; "trade secret" has the same meaning as defined in Government Code section 6254.7; and

(D) The regulated party must not convert spreadsheets in CA-GREET containing formulas into other file formats.

(f) *Approval Process.* To obtain Executive Officer approval of a proposed Method 2A or 2B, the regulated party must submit an application as follows:

(1) *General Information Requirements.*

(A) For a proposed use of Method 2A, the regulated party's application must contain all the information specified in section 95486(c), (e), and (f)(2);

(B) For a proposed use of Method 2B, the regulated party's application must contain all the information specified in section 95486(d), (e)(1), (e)(3), and (f)(2).

(2) *Use of Method 2A or 2B Prohibited Without Executive Officer Approval.* The regulated party must obtain the Executive Officer's written approval pursuant to section 95486(f)(5) of its application submitted pursuant to section 95486(f)(1) above before using a proposed Method 2A or 2B for any purpose under the LCFS regulation. A regulated party that submits any information or documentation in support of a proposed Method 2A or

2B must include a written statement clearly showing that the regulated party understands and agrees to the following:

(A) All information not identified in 95486(e)(3)(C) as trade secrets are subject to public disclosure pursuant to title 17, CCR, sections 91000-91022 and the California Public Records Act (Government Code § 6250 et seq.); and

(B) If the application is approved by the Executive Officer, the carbon intensity values, associated parameters, and other fuel pathway-related information obtained or derived from the application will be incorporated into the LCFS Reporting Tool for use by the applicant. If ~~the application is approved by the Executive Officer, the carbon intensity values, associated parameters, and other fuel pathway-related information obtained or derived from the application will be incorporated into the Method 1 Lookup Table for use on a free, unlimited license, and otherwise unrestricted basis by any person~~;

~~(3) *Completeness/Incompleteness Determination.* After receiving an application submitted under this section, the Executive Officer shall determine whether the application is complete within 15 work days. If the Executive Officer determines the application is incomplete, the Executive Officer shall notify the regulated party accordingly and identify the deficiencies in the application. The deadline set forth in this provision shall also apply to supplemental information submitted in response to an incompleteness determination by the Executive Officer.~~

~~(4) *Public Review*. After determining an application is complete, the Executive Officer shall publish the application and its details on ARB's website at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and make it available for public review. The Executive Officer shall treat all trade secrets specifically identified by the regulated party under section 95486(e)(3)(C) above in accordance with 17 CCR §§ 91000-91022 and the California Public Records Act (Government Code section 6250 et seq.).~~

~~(5) *Final Action.* The Executive Officer shall take final action to approve an application for approval of a new carbon intensity value and associated fuel pathway submitted pursuant to this subsection (f) by amending the Lookup Table(s) in accordance with the rulemaking provisions of the Administrative Procedure Act (Government Code section 11340 et seq.). The Executive Officer shall notify the regulated party accordingly and publish the final action on ARB's website at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm. If the Executive Officer disapproves an application, the disapproval shall identify the basis for the disapproval.~~

(3) Fuel Pathway Application Requirements.

(A) No fuel pathway may be approved under subsection (C) or (D) unless the applicant demonstrates each of the following to the Executive Officer's satisfaction:

1. The fuel that is produced from the proposed pathway would comply with all applicable ASTM standards.

2. The proposed fuel pathway would be covered by an approved Multimedia Analysis, as required under section 95487.

4. If applied for under the Method 2A provisions in Section 95486(c), the proposed fuel pathway must:

a. Result in a fuel carbon intensity reduction of at least 5 gCO_2e/MJ over the applicable reference fuel pathway. The reference fuel pathway is the pathway from the Carbon Intensity Lookup Table that most closely corresponds to the proposed Method 2A pathway.

b. Be for a fuel that the applicant can and expects to provide in California in quantities of not less than 10 million gallons per year.

5. The fuel that would be produced under the proposed pathway would not be exempt from the LCFS under Section 95480.1 (c)

(B) Any person may apply to the Executive Officer for use of a transportation fuel pathway under the LCFS. Unless otherwise noted, all applicants for a certified Method 2A or 2B fuel pathway shall submit the items in the list below.

1. All documents (including spreadsheets and other items not in a standard document format) that contain confidential business information (CBI) must prominently display the phrase “Contains Confidential Business Information” above the main document title and in a running header. Additionally, a separate, redacted version of most such documents must also be submitted. The redacted versions must be approved by the applicant for posting to a public LCFS web site. Within redacted documents, specific redactions must be replaced with the phrase “Confidential

business information has been deleted." This phrase must be displayed clearly and prominently wherever CBI has been redacted.

2. All applications and supporting documents except for the transmittal letter described in (C)(12) below shall be in electronic form unless the Executive Officer has approved or requested in writing another submission format. Documents such as receipts, which are available in paper form only, shall be scanned into an electronic file for submittal. The transmittal letter described in (C)(12) below shall be submitted as an original copy on paper and signed in blue ink.

(C) All applications for LCFS fuel pathway approval shall, unless otherwise noted, include the following:

1. A completed Method 2A/2B application form, which is available at http://www.arb.ca.gov/fuels/2a2b-app.doc.

2. A technical life cycle analysis report, which includes the following information:

a. A detailed description of the full fuel production process. The description should include:

i. A description of the full well-to-wheels fuel life cycle, including the geographic locations where each primary step in the fuel life cycle occurs. This description shall identify where the system boundary was established for the purposes of performing the life cycle analysis on the proposed pathway, and shall be accompanied by a schematic flow chart illustrating the generalized fuel life cycle. The system boundary shall be shown in the schematic.

ii. A description of all feedstocks used, including their points of origination, all feedstock transportation distances and modes, and all pre-processing to which feedstocks are subject. For fuels utilizing agricultural crops for feedstocks, the description shall include the agricultural practices used to produce those crops. This discussion shall cover energy and chemical use, typical crop yields, feedstock harvesting, transport modes and distances, storage, and pre-processing (such as drying or oil extraction). If feedstock transportation modes and distances and/or agricultural practices are unknown, the application shall so state, and shall use CA-GREET defaults for these parameters in the analysis.

iii. A description of all non-feedstock inputs used in the fuel production process. These include, but are not limited to enzymes, fertilizers, chemicals (including agricultural chemicals), and microorganisms.

iv. A description of the transportation modes used throughout the fuel life cycle. This discussion must identify origins and destinations (at least on a regional basis), cargo carrying capacities, fuel shares, and the distances traveled in each case.

v. A description of all facilities involved in the production of fuel under the proposed pathway.

vi. A list of all combustion-powered equipment, along with their respective capacities, sizes, or rated power, fuel utilization type, and proposed use throughout the fuel lifecycle.

vii. A discussion of the thermal and electrical energy consumption that occurs throughout the fuel life cycle. All fuels used (natural gas, biogas, coal, biomass, etc.) must be identified. The electrical energy generation fuel mix used in the CA-GREET analysis must be identified. Internally generated power such as cogeneration and combined heat and power must also be described.

viii. A description of all co-products, byproducts, and waste products associated with production of the proposed fuel.

b. A description of the formal life cycle analysis performed on the proposed pathway. This description must provide clear, detailed information on the energy consumed, the greenhouse gas emissions generated, and the final pathway carbon intensity, as calculated using the approved version of CA-GREET. Important intermediate values in each of the primary life cycle analytical categories shall be shown. Those categories are upstream processes, feedstock and fuel production, feedstock and finished fuel transport, and the use of the fuel in a vehicle. It shall include, at a minimum:

i. A table showing all CA-GREET input values used in the analysis. The worksheet, row, and column locations of the cells into which these inputs were entered shall be identified. The locations of unchanged default values should not be identified. In combination with the inputs identified in item (b)(ii) below, this table shall enable a party unfamiliar with the proposed pathway to enter easily the reported inputs and to replicate the carbon intensity results reported in the application.

ii. A detailed discussion of all modifications other than those covered by item (b)(i) above, made to the CA-GREET spreadsheet. This discussion shall include enough specific detail to enable a party unfamiliar with the proposed pathway to duplicate easily all such modification and, in combination with the inputs identified in item (b)(i) above, replicate the carbon intensity results reported in the application.

iii. Documentation of all non-default CA-GREET values used in the carbon intensity calculation process.

iv. A detailed description of all supporting calculations that were performed outside of the CA-GREET spreadsheet.

c. A list of references covering all information sources used in the preparation of the life cycle analysis. References and citations shall at a minimum, identify the author(s), author’s affiliation, title of the referenced document, publisher, publication date, and pages cited. For internet citations, the reference shall include the universal resource locator (URL) address of the citation, as well as the date the website was last visited.

3. Invoices covering a period of no less than two years for all forms of energy consumed in the fuel production process. The period covered shall be the most recent two-year period of relatively typical operations. Each set of invoices (natural gas, electricity, coal, etc.) shall be accompanied by an Excel spreadsheet summarizing the invoices. Every invoice submitted shall appear as a record in the summary. Each record shall, at a minimum, specify in a separate column the period covered by the purchase, the quantity of energy purchased during that period, the invoice amount, and any special information that applies to that record.

4. If transportation distances other than the ARB-specified defaults are used in the life cycle analysis of the proposed fuel, receipts covering a period of no less than two years for all affected hauling trips shall be provided. Each set of invoices (heavy-duty truck, tanker truck, rail, etc.) shall be accompanied by an Excel spreadsheet summarizing the invoices. Every invoice submitted shall appear as a record in the summary. Each record shall, at a minimum, specify in a separate column the period covered by the purchase, the number of trips purchased, the distance covered by each trip, the invoice amount, and any special information that applies to that record (the notes column need not be populated for every record.)

5. A copy of the CA-GREET spreadsheet prepared for the life cycle analysis of the proposed fuel pathway. All Method 2A and 2B pathway carbon intensities must be calculated using CA-GREET, version 1.8b unless the Executive Officer has approved the use of a method that is both compatible and consistent with the calculation methodology used by GREET version 1.8b.

6. One or more process flow diagrams that, singly or collectively, depict the complete fuel production process. Each piece of equipment or stream appearing on the process flow diagram shall include data on its energy and materials balance, along with any other critical information such as operating temperature, pH, rated capacity, etc.

7. All applicable air pollution control permits issued by the local air pollution control jurisdiction. If air pollution control permits are not required, the life cycle analysis report shall fully explain why this requirement does not exist.

8. Descriptions of all co-located facilities, which in any way utilize outputs from, or provide inputs to the fuel production facility. Such co-located facilities include but are not limited to cogeneration facilities, facilities that process or utilize co-products such as distillers grains with solubles, facilities that provide waste heat to the fuel production process, and facilities which provide or pre-process feedstocks or thermal energy fuels.

9. A copy of the federal Renewable Fuel Standard 2 (RFS2) Third Party Engineering Review Report, if available. If the RFS2 engineering report is not available, the Life Cycle Analysis Report should explain why it is not available.

10. Copies of the federal Renewable Fuel Standard 2 (RFS2) Fuel Producer Co-products Report as required pursuant to 40 CFR 80.14151(b)(1)(ii)(M)-(N). The period covered by the Co-products Report submittal to the Executive Office shall coincide with the period covered by the energy receipts submitted under Paragraph 3, above.

11. Audited statements or reports showing annual finished fuel sales. The period covered by the finished fuel sales reports submittal to the Executive Office shall coincide with the period covered by the energy receipts submitted under Paragraph 3, above

12. A signed transmittal letter from the applicant attesting to the veracity of the information in the application packet and declaring that the information submitted accurately represents the long-term, steady state operation of the fuel production process described in the application packet. The transmittal letter shall

    a. Be the original copy. Photocopies, scanned electronic copies, facsimiles, etc. will not be accepted.

    b. Be on company letterhead.

    c. Be signed in blue ink by a high-ranking responsible official such as a company chief operating officer.

d. Be from the applicant and not from an entity representing the applicant (such as a consultant or legal counsel).

(D) Within 30 calendar days of receipt of an application designated by the applicant as ready for formal evaluation, The Executive Officer shall advise the applicant in writing either that it is complete or that specified additional information is required to make it complete. Within 30 calendar days of submittal of the requested information, the Executive Officer shall advise the applicant in writing either that the application is complete, or that specified additional information is still required before it can be deemed complete. This process can be repeated until one of two outcomes occurs:

1. The Executive Officer deems the packet to be complete and informs the applicant in writing of that outcome.

2. The Executive Officer determines that the applicant is unable to complete the packet and denies the application on that basis. The applicant will be informed in writing of this outcome.

(G) The applicant will be informed in writing of the Executive Officer's findings by no later than 90 calendar days from the date that the application is deemed to be complete.

(H) At any point, and from time to time, during the formal evaluation process, the Executive Officer may request in writing additional information or clarification from the applicant. Between the time that request is issued, and the time the requested information is submitted, no evaluation time, as described in (G), above, will be deemed to have elapsed.

(I) If the Executive Officer is unable to reach a determination within the time period specified in (G) above, the application will be denied without prejudice. This will provide the applicant with time to work with the Executive Officer to overcome the problems the Executive Officer encountered. Once the Executive Officer finds, and informs the applicant in writing, that it is able to proceed with its analysis, it will have another 90 days to reach a finding, as specified in (G) above.

(J) The Executive Officer will evaluate all applications against the following criteria.

1. The Executive Officer will first attempt to replicate the applicant's carbon intensity calculations. If the applicant's calculations can be duplicate, the Executive Officer will continue with the evaluation process. Duplication will proceed as follows:

    i. Starting with a copy of CA-GREET that had not previously been used for calculations associated with the proposed pathway, the Executive Officer will enter all the inputs reported by the applicant under provision (3)(C)(2)b.(i).

    ii. The Executive Officer will then apply all CA-GREET modifications reported by the applicant under provision (3)(C)(2)b.(ii).

    iii. If the Executive Officer is able to duplicate the applicant's CA-GREET results, the application will receive a pass in this area. If the Executive Officer is not able to duplicate the applicant's CA-GREET results, the application shall be denied.

2. Using the energy purchase data obtained from receipts submitted by the applicant and the fuel production accounting data submitted by the applicant, the Executive Officer will attempt to verify the energy consumption inputs to the CA-GREET carbon intensity calculations that were submitted by the applicant pursuant to (C)(2)(b)(i).). If the Executive Officer is unable to verify the applicant's CA-GREET energy consumption inputs by calculating them from energy receipt data and fuel production volumes, the application shall be denied.

(K) If the Executive Officer finds that an application meets the requirements of subsection 95486(f)(3)(J) and determines that the applicant has satisfactorily made the demonstrations identified in subsection 95486(c)), then the Executive Officer will approve in writing the fuel pathway for use by the applicant and shall describe all limitations and operational conditions to which the new pathway will be subject. The Executive Officer shall act on a complete application within the time periods specified in paragraph (G), above.

(L) If the Executive Officer at any time determines that an approved fuel pathway does not meet the operational conditions specified in the written approval issued by the Executive Officer as specified in paragraph (J), above, the Executive Officer shall revoke or modify the approval as is necessary to assure that no fuel that does not meet all applicable operational conditions, including the specified fuel life cycle carbon intensity, is produced for sale in California under that pathway. The Executive Officer shall not revoke or modify a prior certification order without first affording the applicant an opportunity for a hearing in accordance with title 17, California Code of Regulations, part III, chapter 1, subchapter 1, article 4 (commencing with section 60040).

(M) *Recordkeeping.*

1. Each fuel provider that has been approved to use a fuel pathway pursuant to subsection (c) must maintain records identifying each facility at which it produces a transportation fuel for sale in California under the approved fuel pathway. For each such facility, the entity must compile records showing:

   a. the volume of fuel produced and subsequently sold in California under the certified fuel pathway.

   b. the quantity of all forms of energy consumed to produce the fuel covered by paragraph [i]. Thermal energy shall be reported in units of BTUs per gallon and electrical energy in units of kilowatt-hours per gallon of fuel produced. All receipts for the purchase of this fuel shall be maintained and shall be available for presentation to the Executive Officer upon demand.

   c. The quantities of all products co-produced with the fuel covered by certified LCFS pathway. Records shall be kept on only those co-products which are included in the calculation of the pathway carbon intensity. Copies of the federal Renewable Fuel Standard 2 Fuel Producer Co-products Report described in 95486(f)(3)(C)10 will meet this requirement. For co-products for which copies of the federal Renewable Fuel Standard 2 Fuel Producer Co-products Report are not available, Sales receipts and bills of lading for the sale of all such co-products must be available for presentation to the Executive Officer upon demand. If the amount of co-product produced exceeds the amount sold by five percent or more, full documentation of the fate of the unsold fractions shall be maintained shall be available to the Executive Officer upon demand.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95487. Requirements for Multimedia Evaluation

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NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95488. ~~[Reserved]~~ Banking, Trading and Purchase of Credits.

(a) *Calculation of Credit Balance and Annual Compliance Obligation.*

(1) *Compliance Period.* Beginning in 2011 and every year thereafter, the annual compliance period is January 1 through December 31 of each year.

(2) *Calculation of Compliance Obligation and Credit Balance at the End of a Compliance Period.* A regulated party must calculate the credit balance at the end of a compliance period as follows:

$$\textit{Compliance Obligation} = \textit{Deficits}^{\textit{Gen}} + \textit{Deficits}^{\textit{Carried Over}}$$

$$\textit{Credit Balance} = \textit{Credits}^{\textit{Gen}} + \textit{Credits}^{\textit{Acquired}} - \textit{Sum of }(\textit{Credits}^{\textit{retired}} + \textit{Credits}^{\textit{Sold}} + \textit{Credits}^{\textit{Exported}})$$

where:

Deficits$^{\textit{Gen}}$ are the total deficits generated pursuant to section 95485(a) for the current compliance period;

Deficits$^{\textit{Carried Over}}$ are the deficits carried over from the previous compliance period;

$Credits^{Gen}$ are the total credits generated pursuant to section 95488;

$Credits^{Acquired}$ are the total credits purchased or otherwise acquired, including carry back credits acquired pursuant to section 95488(b)(3);

$Credits^{Sold}$ are the total credits sold or otherwise transferred;

$Credits^{Exported}$ are the total credits exported to programs outside the LCFS; and

$Credits^{Retired}$ are the total credits retired within the LCFS.

(3) *Compliance Demonstration.* A regulated party's annual compliance obligation is met when the regulated party demonstrates via its annual report that it possessed and has retired a number of credits from its credit account (established pursuant to section 95488) that is equal to its compliance obligation.

(4) *Deficit Carryover.* A regulated party that does not retire sufficient credits to fully offset its compliance obligation creates a negative credit balance in a compliance period. The regulated party may carry over the deficit to the next compliance period, without penalty, if both the following conditions are met:

(A) the regulated party fully met its annual compliance obligation for the previous compliance period; and

(B) the number of $Credits^{retired}$ for the current annual compliance period is at least equal to 90 percent of the current annual compliance obligation.

(5) *Deficit Reconciliation.*

(A) A regulated party that meets the conditions of deficit carryover, as specified in section 95481(b)(~~3~~4), must eliminate any deficit generated in a given compliance period by the end of the next compliance period. A deficit may be eliminated only by retirement of an equal amount of generated credits ($Credits^{Gen}$), by acquisition of an equal amount of credits from another regulated party ($Credits^{Acquired}$), or by any combination of these two methods.

(B) If the conditions of deficit carryover as specified in section 95481(b)(~~3~~4) are not met, a regulated party is subject to penalties to the extent permitted under State law. In addition, the regulated party must eliminate any deficit generated in a given compliance period by the end of the next compliance period. A deficit may be eliminated only by retirement of an equal amount of generated credits ($Credits^{Gen}$), by acquisition of an equal amount of credits from another regulated party ($Credits^{Acquired}$), or by any combination of these two methods.

(C) A regulated party that is reconciling in the current compliance period a deficit from the previous compliance period under (A) or (B) above remains responsible for meeting the LCFS regulation requirements during the current compliance period.

(b) *Generation and Acquisition of Transferrable Credits.*

(1) Upon submission and acceptance of a quarterly report, the total number of credits generated through the supply of fuels or blendstocks with carbon intensity values below that of the applicable standard will be deposited in a credit account of the applicable regulated party. Once banked, credits maybe retained indefinitely, retired to meet a compliance obligation or transferred to other regulated parties.

(2) The Executive Officer may, at the time of credit creation or credit transfer, assign a unique identification number to each credit. Credits are subject to review and audit by the Executive Officer, and credits may be reversed or adjusted as necessary by the Executive Officer upon a finding that the credits were improperly generated. A proposed credit transfer between regulated parties is also subject to review and verification by the Executive Officer and may be disallowed or adjusted as specified in sections 95488(c)(1)(C)(3) and 95488(c)(4) by the Executive Officer or a third party designated by the Executive Officer.

(3) *Acquisition of "Carry Back" Credits to Meet Obligation.*

(A) *Extended Credit Acquisition Period*. A regulated party may acquire, via purchase or transfer, additional credits between January 1 and March 31 ("extended period") to be used for meeting the compliance obligation of the year immediately prior to the extended period. Credits acquired for this purpose are defined as "carry back" credits.

(B) A carry back credit may be used for the purpose of meeting the compliance of an immediate prior year if all of the conditions below are met:

1. The additional credit was acquired during the extended period, and

2. The additional credit was generated in a compliance year prior to the extended period.

(C) *Use of Carry Back Credits*. Beginning 2012 and each year thereafter, a regulated party may elect to use additional credits purchased during the extended period for the purpose of meeting the obligation of the year immediately prior to the extended period.

1. A regulated party electing to use carry-back credits must identify the number and source of credits it desires to use as carry-back credits in its annual compliance report submitted to the Executive Officer no later than April 30 of the year in which the additional credits were obtained.

2. A regulated party electing to use carry-back credits:

a. Must carry back and retire a sufficient amount of carry back and other credits to meet 100 percent of its compliance obligation in the prior compliance year, or

b. Must minimize its compliance shortfall by retiring all credits purchased during the extended period that are eligible to be used as carry back credits.

(c) *Credit Transfers.*

(1) A regulated party who wishes to sell or transfer credits ("the Seller") and a regulated party who wishes to purchase or acquire a credit ("the Buyer") may enter into an agreement to transfer credits.

(A) *Requirements for the Transfer of Credits.* The Seller may transfer credits provided the number of credits to be transferred by the Seller does not exceed the number of total credits in the Seller's credit account defined as follows:

$$\text{Total Credits} = Credits^{Gen} + Credits^{Acquired} - Sum\ of\ (Credits^{Retired} + Credits^{Sold} + Credits^{Exported})$$

where:

$Credits^{Gen}$, $Credits^{Acquired}$, $Credits^{Retired}$, $Credits^{Sold}$ and $Credits^{Exported}$

have the same meaning as those in section 95488(a).

(B) *Requirements for Documenting a Proposed Credit Transfer.* When a transfer agreement is desired, the Seller shall provide the Buyer a Credit Transfer Form, which is available at http://www.arb.ca.gov/fuels/lcfs/regamend/20111014_LCFS_Credit_Transfer_Form(2).pdf, containing the Seller's signature, date when the signature was entered, and the following information:

1. Date of the proposed Credit transfer agreement.
2. Names of the Seller and Buyer's Company as registered in the LCFS Reporting Tool.
3. The Federal Employer Identification Numbers (FEIN) of the Seller and Buyer's Company as registered in the LCFS Reporting Tool.
4. The first name and last name of the person who performed the transaction on behalf of the Seller's Company.
5. The phone number and email of the person who performed the transaction on behalf of the Seller's Company.
6. The first name and last name of the person who performed the transaction on behalf of the Buyer's Company.
7. The phone number and email of the person who performed the transaction on behalf of the Buyer's Company.
8. The number of credits proposed to be transferred and the credit identification numbers, if any, assigned to the credits by the board.
9. The price or equivalent value of the consideration (in U.S. dollars) to be paid per metric ton of credit proposed for transfer, excluding any fees.

(C) *Requirements for the Purchase of a Credit.*

1. *Confirmation of Agreement for Credit Transfer.* After receiving the Credit Transfer Form from the Seller, it is the Buyer must confirm the accuracy of the information contained in the Credit Transfer Form by signing and dating the Credit Transfer Form.

2. *Reporting to the Executive Officer.* The Buyer shall submit the Credit Transfer Form with all of the required information to the Executive Officer by electronic mail or another submission method as instructed by the Executive Officer.

3. *Recording of a Credit Transfer.* The Executive Officer will record the transfer request, and will update the account balance of the Seller and Buyer to reflect the proposed. Within 5 business days of receiving a Credit Transfer Form, the Executive Officer shall, either:

   a. Process and approve the transfer request and update the account balances of the Seller and Buyer to reflect the proposed, provided the Executive Officer determines all required information was submitted and it accurately reflects the parties' positions at the time of the proposed transfer; or

b. Notify the parties that the proposed is infeasible and identify the reasons for rejecting the transfer.

(2) *Frequency of Credit Transfer.* Credits may be transferred between a Seller and Buyer on a frequency that is agreed upon between the two parties.

(3) *Facilitation of Credit Transfer.* A Seller or Buyer may elect to use a third party (a "credit facilitator") to facilitate the transfer of credits for the Seller, the Buyer or both. The credit facilitator may include, but is not limited to, a credit transfer service agency or broker who assists in arranging the transfer of credits. However, a credit facilitator cannot own or otherwise exercise control over the credit. If the credit facilitator acts on the behalf of the buyer, seller or both to document the proposed transfer pursuant to the requirements of subsections (c) (1) B and C. the credit facilitator must concurrently submit to the Executive Officer documentation showing that the credit facilitator has be authorized to act on behalf of the buyer, seller or both.

(4) *Correcting Credit Transfer Errors.* A regulated party is responsible for the accuracy of information submitted to the Executive Officer. If a regulated party discovers an error in the information reported to the Executive Officer or recorded by the Executive Officer, the regulated party must inform the Executive Officer in writing within five (5) business days of the discovery. If the Executive Officer determines that the regulated party was responsible for the error, the regulated party must submit a corrected Credit Transfer Form. If the Executive Officer determines that the error occurred during the recording of the credit by board staff, the Executive Officer will make the correction and no additional re-submissions are required.

(d) *Mandatory Retirement of Credits for the Purpose of Compliance.*

(1) At the end of a compliance period, a regulated party that possesses credits and has also has incurred deficits must retire a sufficient number of credits so that:

(A) enough credits are retired to completely meet the regulated party's compliance obligation for that compliance period, or

(B) If the total number of credits is less than the total number of deficits, the regulated party must retire all credits within its possession, and

(C) A regulated party that has not retired sufficient credits to meet 100 percent of its compliance obligation at the end of a compliance year must calculate the ratio of all remaining credits to outstanding deficits as specified in section 95488(a)(3).

(2) *Credit Retirement Hierarchy.* A regulated party may specify which credits are to be retired to meet its annual compliance obligation.

(A) Once a credit retirement specification has been submitted by a regulated party in its annual report, it is final and may not be altered.

(B) A regulated party not electing a credit retirement hierarchy will be assigned the default hierarchy provided by the Executive Officer.

(e) *Public Disclosure of Credit and Deficit Balances and Credit Transfer Information.*

(1) The Executive Officer shall, as frequently as he/she deems is feasible and appropriate but no less frequently than quarterly, provide to the public a report containing a summary of credit generation and transfer information including, but not limited to:

(A) Total deficits and credits generated or incurred in the most recent quarter for which data are available, including information on the types and quantities of fuels used to generate credits.

(B) Total deficits and credits generated or incurred in all previous quarters of the most recent year for which data are available, including information on the types and quantities of fuels used to generate credits.

(C) Total credits in possession of regulated parties and the total number of outstanding deficits carried over by regulated parties from a previous compliance year.

(D) Information on the credits transferred during the most recent quarter for which data is available including, but not limited to, the total number of credits transferred, the number transfers, the number of parties making transfers and the monthly average credit price for transfers that reported a price.

(E) Total credits transferred and used as carry-back credits during the first quarter of the current compliance period.

(2) The Executive Officer shall provide reports, as frequently as he/she deems is feasible and appropriate but no less frequently than monthly, to regulated parties and the public containing information necessary or helpful to the functioning of a credit market. Such reports may include recent information on credit transfer volumes, credit prices and price trends and other information determined by the Executive Officer to be of value to market participants and the public. The Executive Officer shall establish, and may periodically modify, a schedule for the routine release of these reports.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95489. Regulation Review.

* * * * *

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

Section 95490. Enforcement Protocols.

Notwithstanding section 95484(b~~c~~) and (c~~d~~), the Executive Officer may enter into an enforceable written protocol with any person to identify conditions under which the person may lawfully meet the recordkeeping, reporting, or demonstration of physical pathway requirements in section 95484(b~~c~~) and (c~~d~~). The Executive Officer may only enter into such a protocol if he or she reasonably determines that the provisions in the protocol are necessary under the circumstances and at least as effective as the applicable provisions specified in section 95484(b~~c~~) and (c~~d~~). Any such protocol shall include the person's agreement to be bound by the terms of the protocol.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference ~~cited~~: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

APPENDIX B

SUMMARY OF LOW CARBON FUEL STANDARD 2011 FIRST QUARTER DATA

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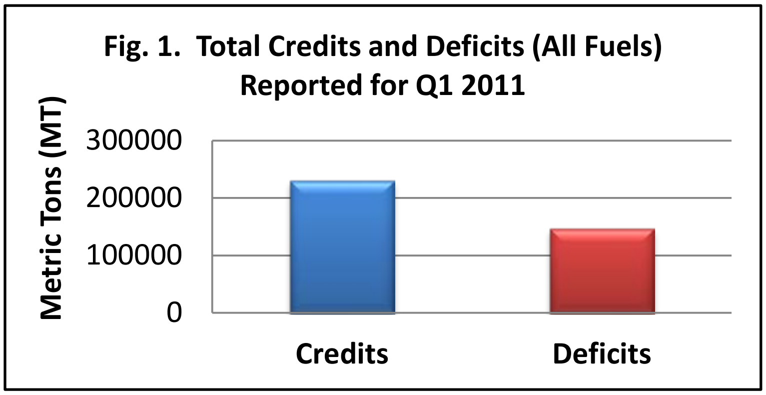
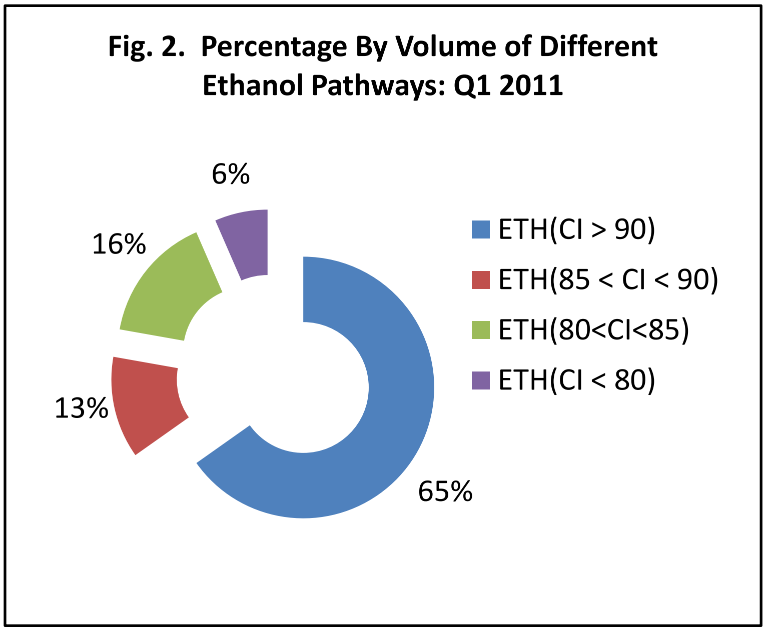
Summary of Low Carbon Fuel Standard
2011 First Quarter (Q1) Data

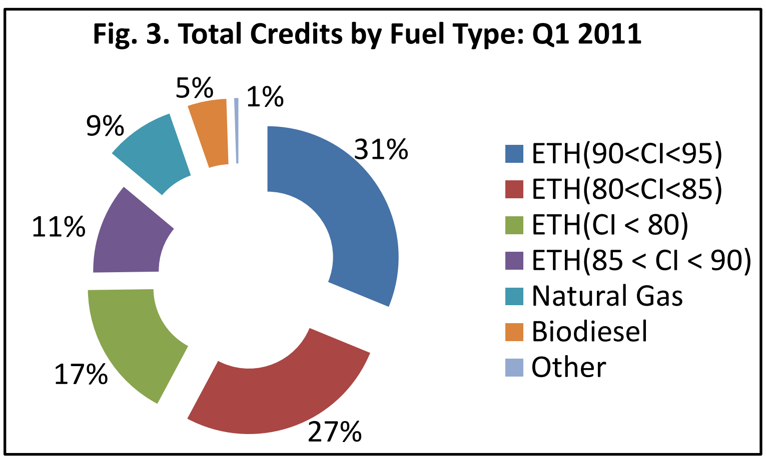
ARB staff has reviewed all first quarter data and can provide the following results. Figure 1 shows the total Q1 credits and deficits reported by regulated parties. As shown, credits exceed deficits by about 75,000 MT; however, this may change as some regulated parties have revised their data.



Currently, a majority of the credits are generated through the production and import of ethanol from various production facilities. As shown in Figure 2, almost two-thirds of the facilities supplying the State are producing ethanol with a CI greater than 90. Of these, about a third are producing ethanol with a 95 CI or more. As the LCFS standards become more stringent, this percentage is expected to decline, while the relative contributions of the lower-CI ethanol will increase.



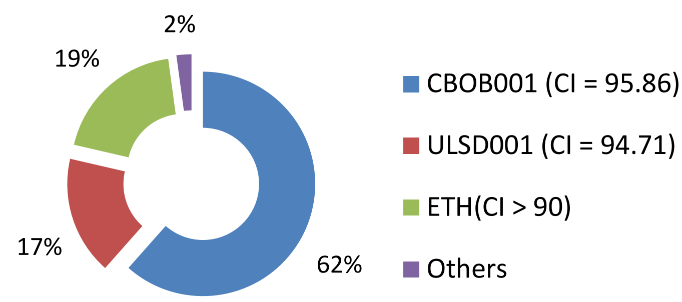
As shown in Figure 3, non-ethanol alternative fuels make up 14 percent of the Q1 credits. However, we expect this to increase significantly as the regulation continues to be implemented. Also, proposed amendments to the regulation may facilitate an increase in alternative fuels. Specifically, staff is proposing rule changes to clarify the opt-in and opt-out procedures based on comments received.



Summary of Low Carbon Fuel Standard 2011 First Quarter (Q1) Data

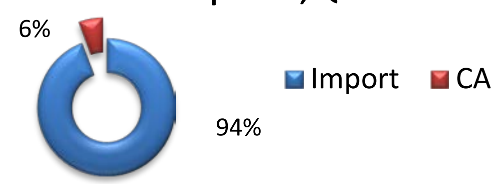
As expected, most deficits result from the sale of CARBOB and ULSD (Fig. 4); however, about 20 percent of the deficits are from ethanol imports with CIs that are higher than the LCFS gasoline standard. ARB staff expects this relative contribution of deficits will decrease as market penetration in California of existing lower-CI ethanol increases over time.

Fig. 4. Total Deficits by Fuel Type: Q1 2011



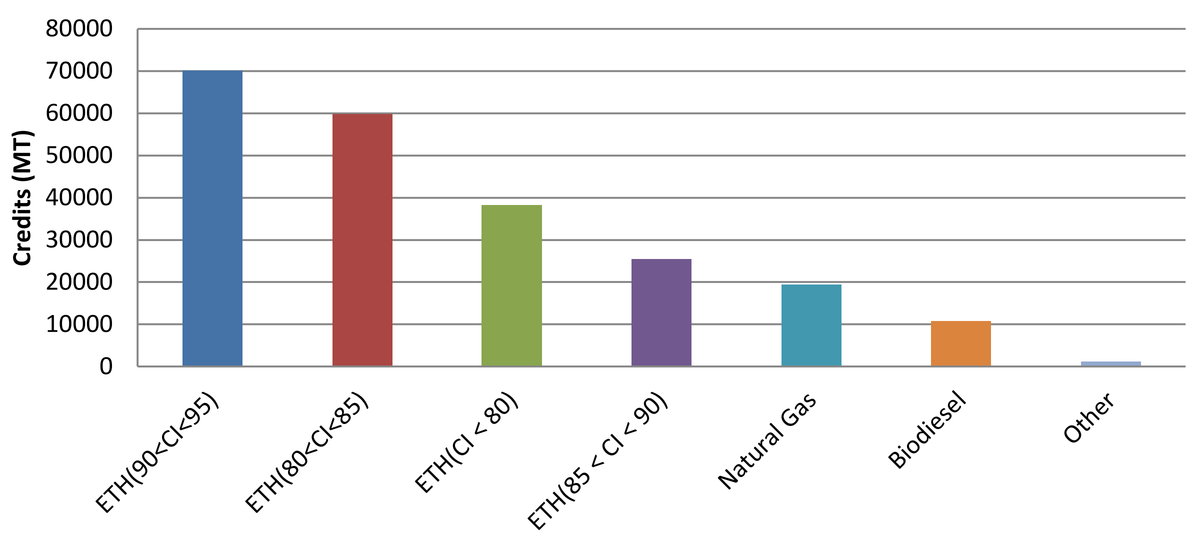
Staff also reviewed the amount of California-produced corn ethanol versus imported product. As Figure 5 shows, the vast majority of corn ethanol used in the State continues to be ethanol that is imported from outside California.

Fig. 5. Ethanol from Corn: Percentage of Total Volume Reported, Q1 2011



Finally, Figure 6 breaks down the total amount of credits generated in Q1 by fuel type. As noted earlier, credits from lower-CI ethanol, natural gas, biodiesel and other transportation fuels (e.g. hydrogen, electricity) are expected to rise with the lower CI standards required under the regulation.

Fig. 6. Tons of Credits Generated By Fuel: Q1 2011



APPENDIX C

CALCULATION OF BASELINE CRUDE AVERAGE CARBON INTENSITY VALUE

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Appendix C

Calculation of Baseline Crude Average Carbon Intensity Value

Composition of Average Crude Oil Refined in California

Table 1 shows the sources of crude oil refined in California for the calendar year 2009. Total volumes of crude oil for California, Alaska, and foreign sources and percentages of crude for each foreign country were obtained from the California Energy Commission.[1] The volume of crude oil produced using thermally enhanced oil recovery (TEOR) in California was obtained from the California Department of Conservation.[2] We assumed that all oil produced using TEOR in California was refined in California.

Table 1: Sources of Crude Oil Refined in California in 2009

Crude Oil Source	Volume (1000 bbl)	Percent of Total CA
California	239,058	
• TEOR	• 117,900	19.48%
• Non-thermal	• 121,158	20.02%
Alaska	91,147	15.06%
Foreign	274,884	
• Saudi Arabia	• 24.92%	11.32%
• Iraq	• 18.68%	8.49%
• Ecuador	• 17.18%	7.80%
• Brazil	• 9.25%	4.20%
• Columbia	• 5.75%	2.61%
• Canada	• 5.08%	2.31%
• Angola	• 5.01%	2.28%
• Oman	• 3.48%	1.58%
• Peru	• 2.10%	0.95%
• Venezuela	• 1.99%	0.90%
• Others	• 6.55%	2.98%

Of the crude oil imported from Canada, we assumed 89 percent was produced using TEOR, bitumen mining and/or upgrading and the remaining crude was produced using conventional recovery methods. Of the crude oil imported from Venezuela, we

[1] California Energy Commission, Energy Almanac Webpage, Oil Supply Sources to California Refineries, viewed on October 6, 2011 at http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts.html.
[2] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.

assumed 51 percent was upgraded prior to transport to California.[3] Of the crude imported from Oman, we assumed 18 percent was recovered using TEOR.[4]

Estimated Carbon Intensity Values for Crude Oil Sources

All crude oil produced using primary or secondary recovery was assigned a “base” carbon intensity value, 4.0 gCO_2/MJ.[5] This value was determined using the GREET model and accounts for crude extraction, venting, and fugitive emissions. Jacobs Consultancy reports similar crude recovery emissions for nine crude sources using primary and secondary recovery methods.[6] Crude recovery estimates obtained using the GHGenius model are also similar and range from 2.2 to 6.3 g/MJ, not including venting or fugitive emissions.[7] Additional emissions from flaring and transport were calculated using state or country-specific data as described below.

Table 2 presents state or country-specific data and calculations for flaring. Data presented for California are continental U.S. values while Alaska data is state specific. Annual flaring volumes are from satellite data published by the National Oceanic and Atmospheric Administration.[8] Crude production values for Alaska, the continental U.S., and foreign countries were obtained from the Energy Information Administration.[9,10] The normalized flaring values are obtained by dividing the annual flaring volumes by the annual crude production volumes. The normalized flaring value is converted to a carbon intensity using a conversion factor of 1.0 scm/bbl being equivalent to 0.49 gCO_2/MJ. The following assumptions were made in deriving the conversion factor:

- The LHV of average crude is 129, 670 BTU/gal.[11] This converts to 5740 MJ/bbl.
- The composition of flared gas is approximately 75 percent methane, 15 percent ethane, 5 percent propane, and 5 percent carbon dioxide.[12]

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[3] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.

[4] Schremp, G., California Energy Commission, 2011, Presentation for Crude Screening Workgroup: Results of Initial Screening Process to Identify Potential HCICOs, revised March 3, 2011.

[5] Wang, M., J. Han, Z. Haq, W. Tyner, M. Wu, and A. Elgowainy, 2011, Energy and greenhouse gas emission effects of corn and cellulosic ethanol with technology improvements and land use changes, Biomass and Bioenergy, 35, 1885-1896.

[6] Jacobs Consultancy, 2011, Presentation: EU Pathway Study – Lifecycle Assessment of Crude Oils in a European Context, September 13, 2011.

[7] O’Connor, Don, October 7, 2011, Email Correspondence: Conventional crude carbon intensity values from GHGenius.

[8] National Oceanic and Atmospheric Administration, 2011, National Geophysical Data Center, Global Gas Flaring Estimates, downloaded from http://www.ngdc.noaa.gov/dmsp/interest/gas_flares.html

[9] U.S. Energy Information Administration, 2011, International Energy Statistics, downloaded from http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=5&pid=57&aid=1&cid=regions,&syid=2006&eyid=2010&unit=TBPD

[10] U.S. Energy Information Administration, 2011, U.S. Crude Oil Production, downloaded from http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm

[11] California Air Resources Board, February 27, 2009, Detailed CA-GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California, Version 2.1

[12] Jacobs Consultancy and Life Cycle Associates, 2009, Life Cycle Assessment Comparison of North American and Imported Crudes, prepared for Alberta Energy Research Institute.

- The flared gas is undergoes complete combustion to carbon dioxide producing 2455 gCO_2/scm.
- 1.15 MJ crude feed will result in 1.0 MJ of fuel products.[13]

Table 2: Flaring Data and Calculations for 2009

Crude Source	Flaring (billion scm/yr)	Crude Production (billion bbl/yr)	Normalized Flaring (scm/bbl)	Carbon Intensity (gCO_2/MJ)
California	0.64	1.7	0.38	0.18
Alaska	1.39	0.259	5.37	2.63
Saudi Arabia	3.39	3.01	1.13	0.55
Iraq	8.08	0.873	9.26	4.54
Ecuador	1.28	0.177	7.23	3.54
Brazil	1.59	0.712	2.23	1.09
Columbia	0.48	0.245	1.96	0.96
Canada	1.85	0.942	1.96	0.96
Angola	3.4	0.696	4.89	2.39
Oman	1.89	0.297	6.36	3.12
Peru	0.04	0.026	1.54	0.75
Venezuela	2.79	0.817	3.41	1.67
Others	147.13	26.41	5.57	2.73

Table 3 presents carbon intensity values for transport of crude oil to California. These estimates were determined using the GREET model.

Table 3: Crude Oil Transport

Crude Source	Transport Carbon Intensity (gCO_2/MJ)
California	0.2
Alaska	0.65
Saudi Arabia	1.82
Iraq	1.85
Ecuador	0.75
Brazil	1.31
Columbia	0.78
Canada	0.79
Angola	1.47
Oman	1.75
Peru	0.77
Venezuela	0.87
Others	1.0

[13] Brandt, A. and S. Unnasch, 2010, Energy Intensity and Greenhouse Gas emissions from Thermal Enhanced Oil Recovery, Energy and Fuels, 24, 4581-4589.

All crude oil produced using TEOR, bitumen mining, and/or upgrading was assigned a carbon intensity value for production and transport of 20 gCO_2/MJ. This estimate is based on the following analysis.

- Table 4 shows some literature and model default values for in situ TEOR with upgrading, in situ TEOR without upgrading, and bitumen mining with upgrading.[14,15,16] These values are for Canadian oil sands production. The in situ thermal recovery values assume a steam-to-oil ratio of 3 to 3.4. In 2009, slightly more than half of oil sands production was mined and upgraded with the remainder being in situ production. Approximately 10 percent of in situ production was upgraded. Applying these rough percentages to the default values shown in Table 4 results in an average CI value of 19 g/MJ for Canadian oil sands production and transport. NETL reports similar average carbon intensity for Canadian oil sands of 21 g/MJ.[17]
- Venezuelan extra-heavy crude oil is primarily produced using in situ recovery (thermal and non-thermal) with upgrading. The steam-to-oil ratio for thermal recovery in Venezuela is lower than that for Canada because of higher reservoir temperatures and lower viscosity oil. NETL has estimated an average carbon intensity of 19 g/MJ for production and transport of upgraded Venezuelan extra-heavy crude oil.
- For California TEOR without upgrading, Jacobs provides an estimate of approximately 21 g/MJ which includes an estimated allocation of 2 g/MJ for upstream natural gas emissions. TIAX reports a value of 12.2 g/MJ while Brandt and Unnasch report a value of 27.5 g/MJ.[18]

Table 4: Some Literature CI Values for Crude Produced using TEOR and Mining

Source	In situ TEOR[1] with upgrading to SCO (gCO2e/MJ)	In situ TEOR[1] w/o upgrading to SCO (gCO2e/MJ)	Bitumen mining[2] with upgrading to SCO (gCO2e/MJ)
GHGenius	28.6	13.3	19.7
GREET[3]	18.7	13.6	15.4
Jacobs report[4]	~26	~16	~17
TIAX report	26.7	16.6	12.8
Average value[5]	**25 + 1 = 26**	**15 + 1 = 16**	**16 + 4 + 1 = 21**

Notes for Table 4:

1. In situ TEOR
   a. GHGenius: SAGD with steam-to-oil ratio (SOR) of 3.2
   b. Jacobs: SAGD with SOR of 3.0

[14] O'Connor, Don, September 27, 2010, Email Correspondence (2 messages): GHGenius carbon intensity values for oil sands crude.

[15] Jacobs Consultancy and Life Cycle Associates, 2009, Life Cycle Assessment Comparison of North American and Imported Crudes, prepared for Alberta Energy Research Institute.

[16] TIAX, 2009, Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions, prepared for Alberta Energy Research Institute.

[17] NETL, 2009, An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions (Appendix A), DOE/NETL-2009/1362.

[18] Brandt, A. and S. Unnasch, 2010, Energy Intensity and Greenhouse Gas Emissions from Thermal Enhanced Oil Recovery, Energy and Fuels, 24, 4581-4589.

c. TIAX:
   i. With upgrading: SAGD with SOR of 3,
   ii. w/o upgrading: CSS with SOR of 3.4
d. GREET: Process method and SOR unknown.

2. Mining carbon intensity values obtained from the literature do not include land use change/tailings pond emissions.
3. GREET values were taken from Table 6-3 in the TIAX report.
4. Jacobs values from Table 8-7 in Jacobs report. These values do not appear to include venting and flaring emissions. Also, there is some uncertainty about allocation of upstream natural gas emissions between recovery and refining in the Jacobs values. Values in Table 4 (above) include upstream natural gas emissions estimates of 2 g/MJ for in situ recovery with upgrading, 1.5 g/MJ for in situ recovery without upgrading, and 1 g/MJ for mining recovery.
5. Average values include emissions associated with transport of crude oil to the refinery. These are dependent on location but typically are about 1 g/MJ. Bitumen mining value also includes 4 g/MJ to account for land use change/tailings pond emissions. Yeh et al. have estimated these emissions at approximately 4 g/MJ (range 0.8 to 10.2 g/MJ).[19]

Calculation of Baseline Crude Average Carbon Intensity Value

Table 5 shows carbon intensity estimates for conventional crude production by state or country as well as the percentage of crude from that state or country produced using TEOR, bitumen mining, and/or upgrading. The "Total CI" for each state or country is a weighted average of the carbon intensity value for conventional production and the assumed value of 20 gCO_2/MJ for crude produced using TEOR, mining, and upgrading. The Baseline Crude Average carbon intensity of 9.72 gCO_2/MJ is obtained by calculating a weighted average of the state and country "Total CI" values.

Table 5: Baseline Crude Average Carbon Intensity

Crude Source	Percentage of Total CA Crude	Conventional Crude CI (g/MJ)	Percentage TEOR, Mining, Upgraded	Total CI (g/MJ)
California	39.5	4.38	49.3	12.08
Alaska	15.06	7.28	0	7.28
Saudi Arabia	11.32	6.37	0	6.37
Iraq	8.49	10.39	0	10.39
Ecuador	7.81	8.29	0	8.29
Brazil	4.2	6.40	0	6.40
Columbia	2.61	5.74	0	5.74
Canada	2.31	5.75	89	18.43
Angola	2.28	7.86	0	7.86
Oman	1.58	8.87	18	10.87
Peru	0.95	5.52	0	5.52
Venezuela	0.9	6.54	51	13.41
Others	2.98	7.73	0	7.73
Weighted Average				**9.72**

[19] Yeh, S., S. Jordaan, A. Brandt, M. Turetsky, S. Spatari, D. Keith, Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands, *Environ. Sci. Technol.*, 2010, *44* (22), pp 8766–8772.

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3. California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.

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APPENDIX D

California Environmental Protection Agency
Air Resources Board
Stationary Source Division

Supplement to:

Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1)

"Detailed California-Modified GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California"

Release Date: October 28, 2011

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Need for a Supplement to the CARBOB Pathway Document

The LCFS regulation considers 2010 as the baseline year against which a ten percent reduction in GHG emissions is mandated by 2020.[1] Because data for crude oil supplied to CA refineries in 2010 was not available during development of the original regulation, Lookup Table carbon intensity values for CARBOB and diesel were based on available crude supply data for the year 2006. At the time, an assumption was made that the carbon intensity for recovery of crude oil supplied to CA refineries would not change substantially between 2006 and the 2010 baseline year. This assumption turned out to be incorrect as the percentages of crude recovered using thermal methods, mining and upgrading have increased.[2,3] Therefore as part of 2011 Regulatory Amendments to the LCFS, ARB staff is proposing updates to the baseline carbon intensity values for CARBOB and diesel using the most recently available comprehensive set of crude oil supply data from the year 2009. Furthermore, it is ARB staff's intention to revise these values again in 2012 as part of a 15-day change to these Regulatory Amendments. In 2012, comprehensive crude oil supply data will be available for the year 2010. ARB staff will be recalculating the "California average" annually to reflect the most current crude slate. To assist in this effort, staff is working with Professor Adam Brandt at Stanford University to develop a lifecycle assessment tool for calculating carbon intensity values for crude oil recovery.[4,5]

Calculation Methodology for the Baseline Crude Average Carbon Intensity Value

We used a simple approach to calculate the Baseline Crude Average carbon intensity value (see Attachment 1 for details). For crude sources produced using thermally enhanced oil recovery (TEOR), bitumen mining and/or upgrading, a single carbon intensity value of 20 gCO2/MJ was assigned. All other crudes were assumed to be produced using conventional primary or secondary recovery methods. For these crude sources we assumed a common "base" carbon intensity value which accounts for extraction, venting, and fugitive emissions and added to this country specific values for flaring and transportation emissions. Crude oil produced in Californa, Canada, Venezuela, and Oman was recovered using a mixture of production methods. In California, approximately half of the crude was produced using TEOR.[6] For Canada we assumed that 89 percent was produced using TEOR, mining and/or upgrading while for Venezuela we assumed 51 percent was produced with upgrading and for Oman we

[1] Proposed Regulation to Implement the Low Carbon Fuels Standard, ISOR Volume 1, 2009, page V-7
[2] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.
[3] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.
[4] Brandt, A. and H. El-Houjeiri, September 15, 2011, Presentation to ARB Staff: Greenhouse Gas Emissions from Conventional and Unconventional Hydrocarbon Production.
[5] El-Houjeiri, H. and A. Brandt, October 3, 2011, Draft Model: Greenhouse Gas (GHG) Emissions from Upstream Petroleum Operations, Version 11.[6] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.
[6] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.

assumed 18 percent was produced using TEOR.[7,8] The resulting carbon intensity values are shown in Table 1 based on state or country of origin. The Baseline Crude Average carbon intensity, 9.72 gCO_2/MJ, was calculated by weighting these values by the percentage contribution to total crude oil supplied to California refineries.

This value is greater than the value presented in the CARBOB pathway document, 8.07 gCO_2/MJ, for two reasons. First, the calculation methodology is different and results in a slightly greater carbon intensity estimate. Applying the methodology described here to the 2006 crude data results in a carbon intensity for crude recovery and transport of 8.57 gCO_2/MJ. This increase is primarily the result of explicitly accounting for flaring emissions by state or country using satellite data. Crude produced in Alaska, Ecuador, Iraq, Angola, and Oman has flaring emissions that are much greater than assumed in the pathway document. Second, the percentages of TEOR, mining, and/or upgrading have increased from 2006 to 2009. For example, California TEOR has increased from 14.43 percent of total California crude in 2006 to 19.48 percent in 2009. Canadian, Venezuelan, and Omani crude imports have also increased.

Table 1: Baseline Crude Average Carbon Intensity

Crude Source	Percentage of Total CA Crude	Conventional Crude CI (g/MJ)	Percentage TEOR, Mining, Upgraded	Total CI (g/MJ)
California	39.5	4.38	49.3	12.08
Alaska	15.06	7.28	0	7.28
Saudi Arabia	11.32	6.37	0	6.37
Iraq	8.49	10.39	0	10.39
Ecuador	7.81	8.29	0	8.29
Brazil	4.2	6.40	0	6.40
Columbia	2.61	5.74	0	5.74
Canada	2.31	5.75	89	18.43
Angola	2.28	7.86	0	7.86
Oman	1.58	8.87	18	10.87
Peru	0.95	5.52	0	5.52
Venezuela	0.9	6.54	51	13.41
Others	2.98	7.73	0	7.73
Weighted Average				**9.72**

[7] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.
[8] Schremp, G., California Energy Commission, 2011, Presentation for Crude Screening Workgroup: Results of Initial Screening Process to Identify Potential HCICOs, revised March 3, 2011.

Baseline Average Carbon Intensity Value for CARBOB

The Baseline Average carbon intensity value for CARBOB, 97.51 gCO_2/MJ, was determined by substituting the Baseline Crude Average carbon intensity value discussed above for the crude recovery (6.93 gCO_2/MJ) and crude transport (1.14 gCO_2/MJ) values reported in the CARBOB pathway document.[9]

[9] California Air Resources Board, February 27, 2009, Detailed CA-GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California, Version 2.1

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ATTACHMENT 1

Calculation of Baseline Crude Average Carbon Intensity Value

Composition of Average Crude Oil Refined in California

Table 1 shows the sources of crude oil refined in California for the calendar year 2009. Total volumes of crude oil for California, Alaska, and foreign sources and percentages of crude for each foreign country were obtained from the California Energy Commission.[10] The volume of crude oil produced using thermally enhanced oil recovery (TEOR) in California was obtained from the California Department of Conservation.[11] We assumed that all oil produced using TEOR in California was refined in California.

Table 1: Sources of Crude Oil Refined in California in 2009

Crude Oil Source	Volume (1000 bbl)	Percent of Total CA
California	239,058	
• TEOR	• 117,900	19.48%
• Non-thermal	• 121,158	20.02%
Alaska	91,147	15.06%
Foreign	274,884	
• Saudi Arabia	• 24.92%	11.32%
• Iraq	• 18.68%	8.49%
• Ecuador	• 17.18%	7.80%
• Brazil	• 9.25%	4.20%
• Columbia	• 5.75%	2.61%
• Canada	• 5.08%	2.31%
• Angola	• 5.01%	2.28%
• Oman	• 3.48%	1.58%
• Peru	• 2.10%	0.95%
• Venezuela	• 1.99%	0.90%
• Others	• 6.55%	2.98%

Of the crude oil imported from Canada, we assumed 89 percent was produced using TEOR, bitumen mining and/or upgrading and the remaining crude was produced using conventional recovery methods. Of the crude oil imported from Venezuela, we

[10] California Energy Commission, Energy Almanac Webpage, Oil Supply Sources to California Refineries, viewed on October 6, 2011 at http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts.html.
[11] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.

assumed 51 percent was upgraded prior to transport to California.[12] Of the crude imported from Oman, we assumed 18 percent was recovered using TEOR.[13]

Estimated Carbon Intensity Values for Crude Oil Sources

All crude oil produced using primary or secondary recovery was assigned a "base" carbon intensity value, 4.0 gCO_2/MJ.[14] This value was determined using the GREET model and accounts for crude extraction, venting, and fugitive emissions. Jacobs Consultancy reports similar crude recovery emissions for nine crude sources using primary and secondary recovery methods.[15] Crude recovery estimates obtained using the GHGenius model are also similar and range from 2.2 to 6.3 g/MJ, not including venting or fugitive emissions.[16] Additional emissions from flaring and transport were calculated using state or country-specific data as described below.

Table 2 presents state or country-specific data and calculations for flaring. Data presented for California are continental U.S. values while Alaska data is state specific. Annual flaring volumes are from satellite data published by the National Oceanic and Atmospheric Administration.[17] Crude production values for Alaska, the continental U.S., and foreign countries were obtained from the Energy Information Administration.[18,19] The normalized flaring values are obtained by dividing the annual flaring volumes by the annual crude production volumes. The normalized flaring value is converted to a carbon intensity using a conversion factor of 1.0 scm/bbl being equivalent to 0.49 gCO_2/MJ. The following assumptions were made in deriving the conversion factor:

- The LHV of average crude is 129, 670 BTU/gal.[20] This converts to 5740 MJ/bbl.
- The composition of flared gas is approximately 75 percent methane, 15 percent ethane, 5 percent propane, and 5 percent carbon dioxide.[21]

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[12] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.

[13] Schremp, G., California Energy Commission, 2011, Presentation for Crude Screening Workgroup: Results of Initial Screening Process to Identify Potential HCICOs, revised March 3, 2011.

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[15] Jacobs Consultancy, 2011, Presentation: EU Pathway Study – Lifecycle Assessment of Crude Oils in a European Context, September 13, 2011.

[16] O'Connor, Don, October 7, 2011, Email Correspondence: Conventional crude carbon intensity values from GHGenius.

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[18] U.S. Energy Information Administration, 2011, International Energy Statistics, downloaded from http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=5&pid=57&aid=1&cid=regions,&syid=2006&eyid=2010&unit=TBPD

[19] U.S. Energy Information Administration, 2011, U.S. Crude Oil Production, downloaded from http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm

[20] California Air Resources Board, February 27, 2009, Detailed CA-GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California, Version 2.1

[21] Jacobs Consultancy and Life Cycle Associates, 2009, Life Cycle Assessment Comparison of North American and Imported Crudes, prepared for Alberta Energy Research Institute.

- The flared gas is undergoes complete combustion to carbon dioxide producing 2455 gCO_2/scm.
- 1.15 MJ crude feed will result in 1.0 MJ of fuel products.[22]

Table 2: Flaring Data and Calculations for 2009

Crude Source	Flaring (billion scm/yr)	Crude Production (billion bbl/yr)	Normalized Flaring (scm/bbl)	Carbon Intensity (gCO_2/MJ)
California	0.64	1.7	0.38	0.18
Alaska	1.39	0.259	5.37	2.63
Saudi Arabia	3.39	3.01	1.13	0.55
Iraq	8.08	0.873	9.26	4.54
Ecuador	1.28	0.177	7.23	3.54
Brazil	1.59	0.712	2.23	1.09
Columbia	0.48	0.245	1.96	0.96
Canada	1.85	0.942	1.96	0.96
Angola	3.4	0.696	4.89	2.39
Oman	1.89	0.297	6.36	3.12
Peru	0.04	0.026	1.54	0.75
Venezuela	2.79	0.817	3.41	1.67
Others	147.13	26.41	5.57	2.73

Table 3 presents carbon intensity values for transport of crude oil to California. These estimates were determined using the GREET model.

Table 3: Crude Oil Transport

Crude Source	Transport Carbon Intensity (gCO_2/MJ)
California	0.2
Alaska	0.65
Saudi Arabia	1.82
Iraq	1.85
Ecuador	0.75
Brazil	1.31
Columbia	0.78
Canada	0.79
Angola	1.47
Oman	1.75
Peru	0.77
Venezuela	0.87
Others	1.0

[22] Brandt, A. and S. Unnasch, 2010, Energy Intensity and Greenhouse Gas emissions from Thermal Enhanced Oil Recovery, Energy and Fuels, 24, 4581-4589.

All crude oil produced using TEOR, bitumen mining, and/or upgrading was assigned a carbon intensity value for production and transport of 20 gCO_2/MJ. This estimate is based on the following analysis.

- Table 4 shows some literature and model default values for in situ TEOR with upgrading, in situ TEOR without upgrading, and bitumen mining with upgrading.[23,24,25] These values are for Canadian oil sands production. The in situ thermal recovery values assume a steam-to-oil ratio of 3 to 3.4. In 2009, slightly more than half of oil sands production was mined and upgraded with the remainder being in situ production. Approximately 10 percent of in situ production was upgraded. Applying these rough percentages to the default values shown in Table 4 results in an average CI value of 19 g/MJ for Canadian oil sands production and transport. NETL reports similar average carbon intensity for Canadian oil sands of 21 g/MJ.[26]
- Venezuelan extra-heavy crude oil is primarily produced using in situ recovery (thermal and non-thermal) with upgrading. The steam-to-oil ratio for thermal recovery in Venezuela is lower than that for Canada because of higher reservoir temperatures and lower viscosity oil. NETL has estimated an average carbon intensity of 19 g/MJ for production and transport of upgraded Venezuelan extra-heavy crude oil.
- For California TEOR without upgrading, Jacobs provides an estimate of approximately 21 g/MJ which includes an estimated allocation of 2 g/MJ for upstream natural gas emissions. TIAX reports a value of 12.2 g/MJ while Brandt and Unnasch report a value of 27.5 g/MJ.[27]

Table 4: Some Literature CI Values for Crude Produced using TEOR and Mining

Source	In situ TEOR[1] with upgrading to SCO (gCO2e/MJ)	In situ TEOR[1] w/o upgrading to SCO (gCO2e/MJ)	Bitumen mining[2] with upgrading to SCO (gCO2e/MJ)
GHGenius	28.6	13.3	19.7
GREET[3]	18.7	13.6	15.4
Jacobs report[4]	~26	~16	~17
TIAX report	26.7	16.6	12.8
Average value[5]	**25 + 1 = 26**	**15 + 1 = 16**	**16 + 4 + 1 = 21**

Notes for Table 4:

1. In situ TEOR
    a. GHGenius: SAGD with steam-to-oil ratio (SOR) of 3.2
    b. Jacobs: SAGD with SOR of 3.0

[23] O'Connor, Don, September 27, 2010, Email Correspondence (2 messages): GHGenius carbon intensity values for oil sands crude.
[24] Jacobs Consultancy and Life Cycle Associates, 2009, Life Cycle Assessment Comparison of North American and Imported Crudes, prepared for Alberta Energy Research Institute.
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[27] Brandt, A. and S. Unnasch, 2010, Energy Intensity and Greenhouse Gas Emissions from Thermal Enhanced Oil Recovery, Energy and Fuels, 24, 4581-4589.

c. TIAX:
    i. With upgrading: SAGD with SOR of 3,
    ii. w/o upgrading: CSS with SOR of 3.4
d. GREET: Process method and SOR unknown.

2. Mining carbon intensity values obtained from the literature do not include land use change/tailings pond emissions.
3. GREET values were taken from Table 6-3 in the TIAX report.
4. Jacobs values from Table 8-7 in Jacobs report. These values do not appear to include venting and flaring emissions. Also, there is some uncertainty about allocation of upstream natural gas emissions between recovery and refining in the Jacobs values. Values in Table 4 (above) include upstream natural gas emissions estimates of 2 g/MJ for in situ recovery with upgrading, 1.5 g/MJ for in situ recovery without upgrading, and 1 g/MJ for mining recovery.
5. Average values include emissions associated with transport of crude oil to the refinery. These are dependent on location but typically are about 1 g/MJ. Bitumen mining value also includes 4 g/MJ to account for land use change/tailings pond emissions. Yeh et al. have estimated these emissions at approximately 4 g/MJ (range 0.8 to 10.2 g/MJ).[28]

Calculation of Baseline Crude Average Carbon Intensity Value

Table 5 shows carbon intensity estimates for conventional crude production by state or country as well as the percentage of crude from that state or country produced using TEOR, bitumen mining, and/or upgrading. The "Total CI" for each state or country is a weighted average of the carbon intensity value for conventional production and the assumed value of 20 gCO_2/MJ for crude produced using TEOR, mining, and upgrading. The Baseline Crude Average carbon intensity of 9.72 gCO_2/MJ is obtained by calculating a weighted average of the state and country "Total CI" values.

Table 5: Baseline Crude Average Carbon Intensity

Crude Source	Percentage of Total CA Crude	Conventional Crude CI (g/MJ)	Percentage TEOR, Mining, Upgraded	Total CI (g/MJ)
California	39.5	4.38	49.3	12.08
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Brazil	4.2	6.40	0	6.40
Columbia	2.61	5.74	0	5.74
Canada	2.31	5.75	89	18.43
Angola	2.28	7.86	0	7.86
Oman	1.58	8.87	18	10.87
Peru	0.95	5.52	0	5.52
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APPENDIX E

California Environmental Protection Agency
Air Resources Board
Stationary Source Division

Supplement to:

Stationary Source Division, Air Resources Board (February 27, 2009, v.2.1)

"Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG)"

Release Date: October 28, 2011

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Need for a Supplement to the CaRFG Pathway Document

The LCFS compliance schedule for gasoline and substitutes for gasoline is based on the carbon intensity value for CaRFG. As part of the 2011 Regulatory Amendments to the LCFS, ARB staff is proposing a revision to the Baseline Average carbon intensity value for CARBOB that increases the value from 95.86 to 97.51 gCO_2/MJ.[1] Because Baseline Average CaRFG is assumed to contain approximately 90 percent CARBOB and 10 percent California Average corn ethanol by volume, the carbon intensity value for CaRFG must be updated as well.

Baseline Average Carbon Intensity Value for CaRFG

On the basis of energy content, CaRFG is assumed to contain 93.48 percent CARBOB and 6.52 percent California Average corn ethanol.[2] Applying this weighting to carbon intensity values for CARBOB, 97.51 gCO_2/MJ, and ethanol, 95.66 gCO_2/MJ, results in a Baseline Average carbon intensity value for CaRFG of 97.39 gCO_2/MJ.

[1] California Air Resources Board: Supplement to Stationary Source Division (February 27, 2009, v.2.1) Detailed California-Modified GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California.

[2] California Air Resources Board: Stationary Source Division (February 27, 2009, v.2.1) Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG).

APPENDIX F

California Environmental Protection Agency
Air Resources Board
Stationary Source Division

Supplement to:

Stationary Source Division, Air Resources Board (February 28, 2009, v.2.1)

"Detailed California-Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California"

Release Date: October 28, 2011

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Need for a Supplement to the ULSD Pathway Document

The LCFS regulation considers 2010 as the baseline year against which a ten percent reduction in GHG emissions is mandated by 2020.[1] Because data for crude oil supplied to CA refineries in 2010 was not available during development of the original regulation, Lookup Table carbon intensity values for CARBOB and diesel were based on available crude supply data for the year 2006. At the time, an assumption was made that the carbon intensity for recovery of crude oil supplied to CA refineries would not change substantially between 2006 and the 2010 baseline year. This assumption turned out to be incorrect as the percentages of crude recovered using thermal methods, mining and upgrading have increased.[2,3] Therefore as part of 2011 Regulatory Amendments to the LCFS, ARB staff is proposing updates to the baseline carbon intensity values for CARBOB and diesel using the most recently available comprehensive set of crude oil supply data from the year 2009. Furthermore, it is ARB staff's intention to revise these values again in 2012 as part of a 15-day change to these Regulatory Amendments. In 2012, comprehensive crude oil supply data will be available for the year 2010. ARB staff will be recalculating the "California average" annually to reflect the most current crude slate. To assist in this effort, staff is working with Professor Adam Brandt at Stanford University to develop a lifecycle assessment tool for calculating carbon intensity values for crude oil recovery.[4,5]

Calculation Methodology for the Baseline Crude Average Carbon Intensity Value

We used a simple approach to calculate the Baseline Crude Average carbon intensity value (see Attachment 1 for details). For crude sources produced using thermally enhanced oil recovery (TEOR), bitumen mining and/or upgrading, a single carbon intensity value of 20 gCO2/MJ was assigned. All other crudes were assumed to be produced using conventional primary or secondary recovery methods. For these crude sources we assumed a common "base" carbon intensity value which accounts for extraction, venting, and fugitive emissions and added to this country specific values for flaring and transportation emissions. Crude oil produced in California, Canada, Venezuela, and Oman was recovered using a mixture of production methods. In California, approximately half of the crude was produced using TEOR.[6] For Canada we assumed that 89 percent was produced using TEOR, mining and/or upgrading while for Venezuela we assumed 51 percent was produced with upgrading and for Oman we

[1] Proposed Regulation to Implement the Low Carbon Fuels Standard, ISOR Volume 1, 2009, page V-7
[2] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.
[3] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.
[4] Brandt, A. and H. El-Houjeiri, September 15, 2011, Presentation to ARB Staff: Greenhouse Gas Emissions from Conventional and Unconventional Hydrocarbon Production.
[5] El-Houjeiri, H. and A. Brandt, October 3, 2011, Draft Model: Greenhouse Gas (GHG) Emissions from Upstream Petroleum Operations, Version 11.
[6] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.

assumed 18 percent was produced using TEOR.[7,8] The resulting carbon intensity values are shown in Table 1 based on state or country of origin. The Baseline Crude Average carbon intensity, 9.72 gCO_2/MJ, was calculated by weighting these values by the percentage contribution to total crude oil supplied to California refineries.

This value is greater than the value presented in the ULSD pathway document, 8.07 gCO_2/MJ, for two reasons. First, the calculation methodology is different and results in a slightly greater carbon intensity estimate. Applying the methodology described here to the 2006 crude data results in a carbon intensity for crude recovery and transport of 8.57 gCO_2/MJ. This increase is primarily the result of explicitly accounting for flaring emissions by state or country using satellite data. Crude produced in Alaska, Ecuador, Iraq, Angola, and Oman has flaring emissions that are much greater than assumed in the pathway document. Second, the percentages of TEOR, mining, and/or upgrading have increased from 2006 to 2009. For example, California TEOR has increased from 14.43 percent of total California crude in 2006 to 19.48 percent in 2009. Canadian, Venezuelan, and Omani crude imports have also increased.

Table 1: Baseline Crude Average Carbon Intensity

Crude Source	Percentage of Total CA Crude	Conventional Crude CI (g/MJ)	Percentage TEOR, Mining, Upgraded	Total CI (g/MJ)
California	39.5	4.38	49.3	12.08
Alaska	15.06	7.28	0	7.28
Saudi Arabia	11.32	6.37	0	6.37
Iraq	8.49	10.39	0	10.39
Ecuador	7.81	8.29	0	8.29
Brazil	4.2	6.40	0	6.40
Columbia	2.61	5.74	0	5.74
Canada	2.31	5.75	89	18.43
Angola	2.28	7.86	0	7.86
Oman	1.58	8.87	18	10.87
Peru	0.95	5.52	0	5.52
Venezuela	0.9	6.54	51	13.41
Others	2.98	7.73	0	7.73
Weighted Average				**9.72**

[7] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.
[8] Schremp, G., California Energy Commission, 2011, Presentation for Crude Screening Workgroup: Results of Initial Screening Process to Identify Potential HCICOs, revised March 3, 2011.

Baseline Average Carbon Intensity Value for ULSD

The Baseline Average carbon intensity value for ULSD, 96.36 gCO_2/MJ, was determined by substituting the Baseline Crude Average carbon intensity value discussed above for the crude recovery (6.93 gCO_2/MJ) and crude transport (1.14 gCO_2/MJ) values reported in the ULSD pathway document.[9]

[9] California Air Resources Board, February 28, 2009, Detailed CA-GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California, Version 2.1

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ATTACHMENT 1

Calculation of Baseline Crude Average Carbon Intensity Value

Composition of Average Crude Oil Refined in California

Table 1 shows the sources of crude oil refined in California for the calendar year 2009. Total volumes of crude oil for California, Alaska, and foreign sources and percentages of crude for each foreign country were obtained from the California Energy Commission.[10] The volume of crude oil produced using thermally enhanced oil recovery (TEOR) in California was obtained from the California Department of Conservation.[11] We assumed that all oil produced using TEOR in California was refined in California.

Table 1: Sources of Crude Oil Refined in California in 2009

Crude Oil Source	Volume (1000 bbl)	Percent of Total CA
California	239,058	
• TEOR	• 117,900	19.48%
• Non-thermal	• 121,158	20.02%
Alaska	91,147	15.06%
Foreign	274,884	
• Saudi Arabia	• 24.92%	11.32%
• Iraq	• 18.68%	8.49%
• Ecuador	• 17.18%	7.80%
• Brazil	• 9.25%	4.20%
• Columbia	• 5.75%	2.61%
• Canada	• 5.08%	2.31%
• Angola	• 5.01%	2.28%
• Oman	• 3.48%	1.58%
• Peru	• 2.10%	0.95%
• Venezuela	• 1.99%	0.90%
• Others	• 6.55%	2.98%

Of the crude oil imported from Canada, we assumed 89 percent was produced using TEOR, bitumen mining and/or upgrading and the remaining crude was produced using conventional recovery methods. Of the crude oil imported from Venezuela, we

[10] California Energy Commission, Energy Almanac Webpage, Oil Sources to California Refineries, viewed on October 6, 2011 at http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts.html.
[11] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.

assumed 51 percent was upgraded prior to transport to California.[12] Of the crude imported from Oman, we assumed 18 percent was recovered using TEOR.[13]

Estimated Carbon Intensity Values for Crude Oil Sources

All crude oil produced using primary or secondary recovery was assigned a "base" carbon intensity value, 4.0 gCO_2/MJ.[14] This value was determined using the GREET model and accounts for crude extraction, venting, and fugitive emissions. Jacobs Consultancy reports similar crude recovery emissions for nine crude sources using primary and secondary recovery methods.[15] Crude recovery estimates obtained using the GHGenius model are also similar and range from 2.2 to 6.3 g/MJ, not including venting or fugitive emissions.[16] Additional emissions from flaring and transport were calculated using state or country-specific data as described below.

Table 2 presents state or country-specific data and calculations for flaring. Data presented for California are continental U.S. values while Alaska data is state specific. Annual flaring volumes are from satellite data published by the National Oceanic and Atmospheric Administration.[17] Crude production values for Alaska, the continental U.S., and foreign countries were obtained from the Energy Information Administration.[18,19] The normalized flaring values are obtained by dividing the annual flaring volumes by the annual crude production volumes. The normalized flaring value is converted to a carbon intensity using a conversion factor of 1.0 scm/bbl being equivalent to 0.49 gCO_2/MJ. The following assumptions were made in deriving the conversion factor:

- The LHV of average crude is 129, 670 BTU/gal.[20] This converts to 5740 MJ/bbl.
- The composition of flared gas is approximately 75 percent methane, 15 percent ethane, 5 percent propane, and 5 percent carbon dioxide.[21]

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[12] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.
[13] Schremp, G., California Energy Commission, 2011, Presentation for Crude Screening Workgroup: Results of Initial Screening Process to Identify Potential HCICOs, revised March 3, 2011.
[14] Wang, M., J. Han, Z. Haq, W. Tyner, M. Wu, and A. Elgowainy, 2011, Energy and greenhouse gas emission effects of corn and cellulosic ethanol with technology improvements and land use changes, Biomass and Bioenergy, 35, 1885-1896.
[15] Jacobs Consultancy, 2011, Presentation: EU Pathway Study – Lifecycle Assessment of Crude Oils in a European Context, September 13, 2011.
[16] O'Connor, Don, October 7, 2011, Email Correspondence: Conventional crude carbon intensity values from GHGenius.
[17] National Oceanic and Atmospheric Administration, 2011, National Geophysical Data Center, Global Gas Flaring Estimates, downloaded from http://www.ngdc.noaa.gov/dmsp/interest/gas_flares.html
[18] U.S. Energy Information Administration, 2011, International Energy Statistics, downloaded from http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=5&pid=57&aid=1&cid=regions,&syid=2006&eyid=2010&unit=TBPD
[19] U.S. Energy Information Administration, 2011, U.S. Crude Oil Production, downloaded from http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm
[20] California Air Resources Board, February 27, 2009, Detailed CA-GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California, Version 2.1
[21] Jacobs Consultancy and Life Cycle Associates, 2009, Life Cycle Assessment Comparison of North American and Imported Crudes, prepared for Alberta Energy Research Institute.

- The flared gas is undergoes complete combustion to carbon dioxide producing 2455 gCO_2/scm.
- 1.15 MJ crude feed will result in 1.0 MJ of fuel products.[22]

Table 2: Flaring Data and Calculations for 2009

Crude Source	Flaring (billion scm/yr)	Crude Production (billion bbl/yr)	Normalized Flaring (scm/bbl)	Carbon Intensity (gCO_2/MJ)
California	0.64	1.7	0.38	0.18
Alaska	1.39	0.259	5.37	2.63
Saudi Arabia	3.39	3.01	1.13	0.55
Iraq	8.08	0.873	9.26	4.54
Ecuador	1.28	0.177	7.23	3.54
Brazil	1.59	0.712	2.23	1.09
Columbia	0.48	0.245	1.96	0.96
Canada	1.85	0.942	1.96	0.96
Angola	3.4	0.696	4.89	2.39
Oman	1.89	0.297	6.36	3.12
Peru	0.04	0.026	1.54	0.75
Venezuela	2.79	0.817	3.41	1.67
Others	147.13	26.41	5.57	2.73

Table 3 presents carbon intensity values for transport of crude oil to California. These estimates were determined using the GREET model.

Table 3: Crude Oil Transport

Crude Source	Transport Carbon Intensity (gCO_2/MJ)
California	0.2
Alaska	0.65
Saudi Arabia	1.82
Iraq	1.85
Ecuador	0.75
Brazil	1.31
Columbia	0.78
Canada	0.79
Angola	1.47
Oman	1.75
Peru	0.77
Venezuela	0.87
Others	1.0

[22] Brandt, A. and S. Unnasch, 2010, Energy Intensity and Greenhouse Gas emissions from Thermal Enhanced Oil Recovery, Energy and Fuels, 24, 4581-4589.

All crude oil produced using TEOR, bitumen mining, and/or upgrading was assigned a carbon intensity value for production and transport of 20 gCO_2/MJ. This estimate is based on the following analysis.

- Table 4 shows some literature and model default values for in situ TEOR with upgrading, in situ TEOR without upgrading, and bitumen mining with upgrading.[23,24,25] These values are for Canadian oil sands production. The in situ thermal recovery values assume a steam-to-oil ratio of 3 to 3.4. In 2009, slightly more than half of oil sands production was mined and upgraded with the remainder being in situ production. Approximately 10 percent of in situ production was upgraded. Applying these rough percentages to the default values shown in Table 4 results in an average CI value of 19 g/MJ for Canadian oil sands production and transport. NETL reports similar average carbon intensity for Canadian oil sands of 21 g/MJ.[26]
- Venezuelan extra-heavy crude oil is primarily produced using in situ recovery (thermal and non-thermal) with upgrading. The steam-to-oil ratio for thermal recovery in Venezuela is lower than that for Canada because of higher reservoir temperatures and lower viscosity oil. NETL has estimated an average carbon intensity of 19 g/MJ for production and transport of upgraded Venezuelan extra-heavy crude oil.
- For California TEOR without upgrading, Jacobs provides an estimate of approximately 21 g/MJ which includes an estimated allocation of 2 g/MJ for upstream natural gas emissions. TIAX reports a value of 12.2 g/MJ while Brandt and Unnasch report a value of 27.5 g/MJ.[27]

Table 4: Some Literature CI Values for Crude Produced using TEOR and Mining

Source	In situ TEOR[1] with upgrading to SCO (gCO2e/MJ)	In situ TEOR[1] w/o upgrading to SCO (gCO2e/MJ)	Bitumen mining[2] with upgrading to SCO (gCO2e/MJ)
GHGenius	28.6	13.3	19.7
GREET[3]	18.7	13.6	15.4
Jacobs report[4]	~26	~16	~17
TIAX report	26.7	16.6	12.8
Average value[5]	**25 + 1 = 26**	**15 + 1 = 16**	**16 + 4 + 1 = 21**

Notes for Table 4:

1. In situ TEOR
    a. GHGenius: SAGD with steam-to-oil ratio (SOR) of 3.2
    b. Jacobs: SAGD with SOR of 3.0

[23] O'Connor, Don, September 27, 2010, Email Correspondence (2 messages): GHGenius carbon intensity values for oil sands crude.
[24] Jacobs Consultancy and Life Cycle Associates, 2009, Life Cycle Assessment Comparison of North American and Imported Crudes, prepared for Alberta Energy Research Institute.
[25] TIAX, 2009, Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions, prepared for Alberta Energy Research Institute.
[26] NETL, 2009, An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions (Appendix A), DOE/NETL-2009/1362.
[27] Brandt, A. and S. Unnasch, 2010, Energy Intensity and Greenhouse Gas Emissions from Thermal Enhanced Oil Recovery, Energy and Fuels, 24, 4581-4589.

c. TIAX:
    i. With upgrading: SAGD with SOR of 3,
    ii. w/o upgrading: CSS with SOR of 3.4
d. GREET: Process method and SOR unknown.

2. Mining carbon intensity values obtained from the literature do not include land use change/tailings pond emissions.
3. GREET values were taken from Table 6-3 in the TIAX report.
4. Jacobs values from Table 8-7 in Jacobs report. These values do not appear to include venting and flaring emissions. Also, there is some uncertainty about allocation of upstream natural gas emissions between recovery and refining in the Jacobs values. Values in Table 4 (above) include upstream natural gas emissions estimates of 2 g/MJ for in situ recovery with upgrading, 1.5 g/MJ for in situ recovery without upgrading, and 1 g/MJ for mining recovery.
5. Average values include emissions associated with transport of crude oil to the refinery. These are dependent on location but typically are about 1 g/MJ. Bitumen mining value also includes 4 g/MJ to account for land use change/tailings pond emissions. Yeh et al. have estimated these emissions at approximately 4 g/MJ (range 0.8 to 10.2 g/MJ).[28]

Calculation of Baseline Crude Average Carbon Intensity Value

Table 5 shows carbon intensity estimates for conventional crude production by state or country as well as the percentage of crude from that state or country produced using TEOR, bitumen mining, and/or upgrading. The "Total CI" for each state or country is a weighted average of the carbon intensity value for conventional production and the assumed value of 20 gCO_2/MJ for crude produced using TEOR, mining, and upgrading. The Baseline Crude Average carbon intensity of 9.72 gCO_2/MJ is obtained by calculating a weighted average of the state and country "Total CI" values.

Table 5: Baseline Crude Average Carbon Intensity

Crude Source	Percentage of Total CA Crude	Conventional Crude CI (g/MJ)	Percentage TEOR, Mining, Upgraded	Total CI (g/MJ)
California	39.5	4.38	49.3	12.08
Alaska	15.06	7.28	0	7.28
Saudi Arabia	11.32	6.37	0	6.37
Iraq	8.49	10.39	0	10.39
Ecuador	7.81	8.29	0	8.29
Brazil	4.2	6.40	0	6.40
Columbia	2.61	5.74	0	5.74
Canada	2.31	5.75	89	18.43
Angola	2.28	7.86	0	7.86
Oman	1.58	8.87	18	10.87
Peru	0.95	5.52	0	5.52
Venezuela	0.9	6.54	51	13.41
Others	2.98	7.73	0	7.73
Weighted Average				**9.72**

[28] Yeh, S., S. Jordaan, A. Brandt, M. Turetsky, S. Spatari, D. Keith, Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands, *Environ. Sci. Technol.*, 2010, *44* (22), pp 8766–8772.

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17. U.S. Energy Information Administration, 2011, International Energy Statistics, downloaded from http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=5&pid=57&aid=1&cid=regions,&syid=2006&eyid=2010&unit=TBPD.

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21. Brandt, A. and S. Unnasch, 2010, Energy Intensity and Greenhouse Gas emissions from Thermal Enhanced Oil Recovery, Energy and Fuels, 24, 4581-4589.

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26. Brandt, A. and S. Unnasch, 2010, Energy Intensity and Greenhouse Gas Emissions from Thermal Enhanced Oil Recovery, Energy and Fuels, 24, 4581-4589.

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APPENDIX G

CREDIT TRANSFER FORM
CREDIT ALLOCATION FORM

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LCFS Credit Transfer Form_10282011-v1

The Low Carbon Fuel Standard (LCFS) Credit Transfer Form is used by the Air Resources Board (ARB) to document and initiate transfers of LCFS credits between a Transferor (Seller) and a Transferee (Buyer). ARB will record the information herein and adjust the credit balances of both the Seller and Buyer after the form is received by ARB, as required under section 95488 of the LCFS Regulation.

Important: This form must be used and submitted each time a credit transfer agreement has been made, regardless of the number of credits transferred and the price per unit credit. Submit a Credit Transfer Form within 30 days of the actual trade. Only credits that have been "banked" in the LRT can be traded.

Instructions:

This LCFS Credit Transfer Form must be completed by the Seller and provided to the Buyer upon the transfer of a LCFS credit. The Buyer is responsible for submitting the form to ARB for timely account processing and recording.

The following information should be available prior to completing the form:

1. Seller and Buyer's organization names as they appear in the LCFS Reporting Tool.
2. Seller and Buyer's organization FEINs as they appear in the LCFS Reporting Tool.
3. Authorized representatives of both the Seller's and Buyer's organization (including name and contact information).
4. The number of credits transferred during a reporting period.

The information submitted is subject to ARB verification. The Seller and Buyer may be contacted by ARB to confirm the transactions reported.

Technical Requirements:

This form may be downloaded in Microsoft InfoPath format or in Microsoft Word format.

If InfoPath format is used, this form may be digitally signed below and submitted to ARB by clicking the button below. (You must have InfoPath to complete the form).

If Word format is used, this form should be completed, signed, and email as an attachment to Greg O'Brien at gobrien@arb.ca.gov with the subject heading LCFS Credit Transfer Form.

Submission instructions appear at the end of the form.

Section 1. Reporting Period

Enter the period in which the credit transfer is to be recorded.

● 2011 - Q1

● 2011 - Q2

- 2011 - Q3
- 2011 - Q4
- 2012 - Q1
- 2012 - Q2

Section 2. Transferor (Seller) Details

Enter the Seller's company name and FEIN as registered in the LCFS Reporting Tool.

Seller Company Name: Seller Company FEIN:

Enter all company representative(s) who participated in the credit transfer. If the credit transfer was mediated by a broker, please indicate "broker" and enter the broker's information below. At least one company representative is required.

(For InfoPath users, click "Add More Sellers" below to enter more names. Word users may attach additional names on a separate page).

Seller Representative: (First Name and Last Name)

Seller Phone Number: (123-456-7890)

Seller Email:

☐ Broker (Check here if the Seller is being represented by a broker or other credit transfer facilitator)

Note: Brokers/facilitators must include submittal of a copy of authorization to act on behalf of the Buyer/Seller or both.

Section 3. Transferee (Buyer) Details

Enter the Buyer's organization name and FEIN as registered in the LCFS Reporting Tool.

Buyer Company Name: Buyer Company FEIN:

Enter all company representative(s) who participated in the credit transfer. If the credit transfer was mediated by a broker, please indicate "broker" and enter the broker's information below. At least one company representative is required.

(For InfoPath users, click "Add More Buyers" below to enter more names. Word users may attach additional names on a separate page).

Buyer Representative: (First Name and Last Name)

Buyer Phone Number: (123-456-7890)

Buyer Email:

☐ Broker (Check here if the Seller is being represented by a broker or other credit transfer facilitator)

Note: Brokers/facilitators must include submittal of a copy of authorization to act on behalf of the Buyer/Seller or both.

Section 4. Credit Transfer Details

Enter the credit transfer information below. For multiple transfers between the Seller and Buyer, complete a separate form for each transfer.

Proposed Credit Transfer Date:

(mm/dd/yyyy)

Number of Credits Transferred: (in units of 1MT)

Average Price Per Unit Credit: (excluding any fees)

ID numbers of credits (if available through ARB) ___________

Quarter in which credits were generated ________

Section 5. Review and Confirm

Review the information entered. Enter a signature for each Seller and Buyer listed in sections 2 and 3. By signing, each person below declares that all information provided herein are true and correct, and to the best of his/her knowledge and belief.

Note: The buyer and seller representatives need to have an account in the LRT and have “Signatory Authority” in the LRT in order to use the LCFS Credit Transfer Form. The regulated party LRT administrators can set up any representative of the company with this authority.

Seller Confirmation

Seller Representative Signature(s)	***Signed Date***

Buyer Confirmation

Buyer Representative Signature(s)	***Signed Date***

How to Submit This Form:

Sellers:
Upon agreement to transfer a credit, complete the form and provide a signed copy to the Buyer.

If you are using Microsoft InfoPath to fill out this form, you may digitally sign and date the form. ***You should save the form and email it to the Buyer as an attachment (do not change the file format of .xml).***

Alternatively, if you are using a Word version of the form, you will need to print the form, sign it, and provide the original copy to the Buyer.

Buyers:
Upon receiving the form, confirm the information provided by the Seller. If you received a Microsoft InfoPath version of the form, you may digitally sign the form and click the button below to email the form to ARB (you must also have InfoPath on your computer).

Alternatively, if you received a hard copy or Word version of the form from the Seller, you will need to sign it and email the form containing both the Seller and Buyer signatures.

Email the completed form attachment to Greg O'Brien gobrien@arb.ca.gov with the subject heading LCFS Credit Transfer Form.

For ARB Internal Use Only

Form ID:

Date Received: ____________

Date Recorded: _____________

Staff Name:

LCFS Credit Allocation Form_10282011-v1

The LCFS Credit Allocation Form is used by the Air Resources Board (ARB) to determine the allocation and retirement sequence of credits held by a regulated party for the purpose of meeting a compliance obligation under section 95488 of the LCFS Regulation. **Note:** This form is only necessary if the California Air Resources Board has developed a method to identify unique credits.

A Credit Allocation Form should be submitted by regulated parties as part of the LCFS Annual Report when there is an existing Annual Compliance Obligation. If it is not submitted the "Default Order" defined in Section 2 below will be used to retire credits toward meeting any existing compliance obligation.

Instructions:

An authorized representative of the company should complete, sign, and submit the form. This form should be submitted as part of the LCFS Annual Report.

Technical Requirements:

This form may be downloaded in Microsoft InfoPath format or in Microsoft Word format.

If InfoPath format is used, this form may be digitally signed below and submitted to ARB by clicking the button below. (You must have InfoPath to complete the form).

If Word format is used, this form may be completed, printed, signed, and email as an attachment to Greg O'Brien at gobrien@arb.ca.gov with subject heading LCFS Credit Allocation Form.

Submission instructions appear at the end of the form.

Section 1. Company Information

Company Name:

Company FEIN:

Company Representative Name:

Company Representative Phone:

Company Representative Email:

Section 2. Credit Retirement

I elect to retire LCFS credits for my company in the following manner (If a box is not checked the “Default Order” below will be applied):

☐ 1. I have attached a Credit Retirement Specification Form which identifies all credits to be retired, Or

☐ 2. Enter the credit retirement preference (1,2,3 or leave blank as applicable) below:

☐. Retire those acquired carry-back credits my company acquired during the Extended Credit Purchase Period of January 1 to March 31 following the prior compliance period (in order of earlist transfer “recording date” first).

“Carry-back” credits can be acquired during the Extended Credit Purchase Period of January 1 through March 31 and are designated as carry-back to meet the Annual Compliance Obligation. (For further details refer to section 95488 of the LCFS Regulation)

☐. Retire those acquired credits my company acquired during any compliance year (in order of earliest transfer “recording date” first).
“**Recording date**” is the date that ARB completes the recording of a credit transfer in the LRT.

☐. Retire those credits my company generated in any compliance year (in order of the earliest quarter first in which the credits were generated).

“Default Order” for credit retirement (in order of execution below if box in Section3 is not checked and/or order preference not indicated)

1. Retire those acquired credits my company acquired during the Extended Credit Purchase Period of January 1 to March 31 following the prior compliance period and designated for carry-back.
2. Retire those acquired credits my company acquired during a previous compliance period (in order of earlist transfer “recording date” first).
3. Retire those credits my company generated in a previous compliance year (in order of the earliest quarter first in which the credits were generated).

Note: All available credits will be applied in the quantity necessary to meet an existing Annual Compliance Obligation.

A “**previous compliance year**” includes all annual compliance periods prior to the year in which the annual report is filed.

Confirmation

Enter signature and date. By signing, I declare that all information provided herein are true and correct, and to the best of my knowledge and belief.

Date:

Signature of the person in Section 1

How to Submit This Form:

If you are using Microsoft InfoPath to fill out this form, you may digitally sign and date the form and email the form to ARB by click the button below.

Alternatively, if you are using a Word version of the form, you will need to print the form, sign it, and email the form to Greg O'Brien at gobrien@arb.ca.gov with subject heading LCFS Credit Allocation Form.

ARB Internal Use

Date Received:

Staff Name:

Change Date: