California Environmental Protection Agency
Air Resources Board

Proposed Regulation to Implement the Low Carbon Fuel Standard

Volume I

Staff Report: Initial Statement of Reasons

Release Date: March 5, 2009

State of California

California Environmental Protection Agency
AIR RESOURCES BOARD
Stationary Source Division

STAFF REPORT: INITIAL STATEMENT OF REASONS PROPOSED REGULATION TO IMPLEMENT THE LOW CARBON FUEL STANDARD

Volume I

Public Hearing to Consider the Proposed Regulation
to Implement the Low Carbon Fuel Standard

Date of Release: March 5, 2009
Scheduled for Consideration: April 23, 2009

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This Page Left Intentionally Blank

Acknowledgments

This report was prepared with the assistance and support from many individuals within the Air Resources Board; only the principal contributors. In addition, staff would like to acknowledge the assistance and cooperation that we have received from many individuals and organizations, too numerous to list, whose contributions throughout the development process have been invaluable. Finally, staff would like to acknowledge the significant contributions from the numerous State, federal, and international governmental agencies that have provided assistance throughout the rulemaking process.

Special thanks goes to the late Professor Alexander Farrell, whose tireless efforts to promote the development of a low carbon fuel policy was an inspiration to us all. Thank you Alex.

Air Resources Board
Stationary Source Division
Principal Contributors

Kevin Cleary
James Duffy, Ph.D
Chris Gallenstein
Alan Glabe, Ph.D.
Wes Ingram, Ph.D.
Jill Locke
Reza Lorestany, M.S., M.B.A
Carolyn Lozo
Ron Oineza
Eric Patton, P.E
Jim Peterson, M.S
Chan Pham
Anil Prabhu, Ph.D.
Manisha Singh, Ph.D.
Susan Solarz
Marcelle Surovik
Christina Zhang-Tillman, M.S.
Michelle Werner, Ph.D.
Jing Yuan, Ph.D.

Special Thanks To:

Office of Legal Affairs
Tom Jennings
Claudia Nagy

Office of Climate Change
Jeannie Blakeslee
Sam Wade

Research Division
Alvaro Alvarado, Ph.D
Reza Mahdavi, Ph.D

Enforcement Division
Steve Brisby, M.S.
Dickman Lum

Planning and Technical Support Division
Martin Johnson
Beth Schwehr
Jonathon Taylor

Mobile Source Control Division
Craig Childers, P.E.
Ben Deal, P.E.

Acknowledgments
(Continued)

State Water Resources Control Board
Robert Hodam, M.S. Division of Water Quality

California Integrated Waste Management Board
Brian Helmowski, M.S. Climate Change and Technology Section

California Energy Commission
McKinley Addy
Jim Page
Mike McCormack

University of California, Berkeley
Andrew Jones
Dan Kammen, Ph.D.
Michael O'Hare, Ph.D.
Richard Plevin
Sabrina Spatari

University of California, Davis
Bryan Jenkins, Ph.D.
Chris Knittel, Ph.D.
Nathan Parker
Dan Sumner, Ph.D.
Sonia Yeh, Ph.D.

Purdue University
Alla Golub, Ph.D.
Tom Hertel, Ph.D.
Wally Tyner, Ph.D.

Energy Foundation
Jason Mark, Director of Transportation Programs

Life Cycle Associates – Stephan Unasch
Tiax LLC – Jenny Pont

Reviewed by:

Michael H. Scheible, Deputy Executive Officer
Robert D. Fletcher, Chief, Stationary Source Division
Dean C. Simeroth, Chief, Criteria Pollutants Branch
John Courtis, Manager, Alternative Fuels Section
Hardip Judge, Manager, Program Review Section
Renee Littaua, Manager, Fuels Section
Floyd Vergara, Manager, Industrial Section
Michael Waugh, Manager, Program Assistance Section

TABLE OF CONTENTS

Page Number

OTHER APPENDICES

Appendices B through G Are Available Under Separate Cover

Appendix B: Supporting Documentation For The Technology Assessment

Appendix C: Supporting Documentation for Determination of Carbon Intensity Values

Appendix D: LCFS Credit Calculations

Appendix E: Supporting Documentation for the Compliance Scenarios

Appendix F: Supporting Documentation for Environmental Analysis

Appendix G: Supporting Documentation for Economic Analysis

This Page Left Intentionally Blank

Executive Summary

Overview

In this rulemaking, the Air Resources Board (ARB/ Board) staff is proposing to reduce emissions of greenhouse gases (GHG) by lowering the carbon content of transportation fuels used in California. The regulation is referred to as the California Low Carbon Fuel Standard (LCFS). The LCFS will reduce GHG emissions from the transportation sector in California by about 16 million metric tons (MMT) in 2020. These reductions account for almost 10 percent of the total GHG emission reductions needed to achieve the State's mandate of reducing GHG emissions to 1990 levels by 2020. In addition, the LCFS is designed to reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of alternative, low-carbon fuels in California. Governor Schwarzenegger has identified all of these outcomes as important goals for California.

The LCFS is designed to provide a durable framework that uses market mechanisms to spur the steady introduction of lower carbon fuels. The framework establishes performance standards that fuel producers and importers must meet each year beginning in 2011. One standard is established for gasoline and the alternative fuels that can replace it. A second similar standard is set for diesel fuel and its replacements. Each standard is set to achieve an average 10 reduction in the carbon intensity of the statewide mix transportation fuels by 2020.

The standards are "back-loaded"; that is, there are more reductions required in the last five years, than the first five years. This schedule allows for the development of advanced fuels that are lower in carbon than today's fuels and the penetration of plug-in hybrid electric vehicles, battery electric vehicles, fuel cell vehicles, and flexible fuel vehicles. The staff anticipates that compliance with the LCFS will be based on a combination of strategies involving lower carbon fuels and more efficient, advanced-technology vehicles.

Reformulated gasoline mixed with corn-derived ethanol at 10 percent by volume and low sulfur diesel fuel represent the baseline fuels. Lower carbon fuels may be ethanol, biodiesel, renewable diesel, or blends of these fuels with gasoline or diesel as appropriate. Compressed natural gas and liquefied natural gas also may be low carbon fuels. Hydrogen and electricity are also low carbon fuels and result in significant reductions of GHGs when used in fuel cell or electric vehicles due to significant vehicle power train efficiency improvements over conventionally-fueled vehicles. As such, these fuels are included in the LCFS as low carbon options. Other fuels may be used to meet the standards and are subject to meeting existing requirements for transportation fuels.

The LCFS framework is based on the premise that each fuel has a "lifecycle" GHG emission value that is then compared to a standard.[1] This lifecycle analysis represents the GHG emissions associated with the production, transportation, and use of low carbon fuels in motor vehicles. The lifecycle analysis includes the direct emissions associated with producing, transporting, and using the fuels. In addition, the lifecycle analysis considers any other effects, both direct and indirect, that are caused by the change in land use or other effects. For some crop-based biofuels, the staff has identified land use changes as a significant source of additional GHG emissions. Therefore, the staff is proposing that emissions associated with land use changes be included in the carbon intensity values assigned to those fuels in the regulation. 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.

The standards are expressed as the carbon intensity of gasoline and diesel fuel and their alternatives. Measured on a lifecycle basis, the carbon intensity represents the equivalent amount of carbon dioxide (CO_2e) emitted from each stage of producing, transporting, and using the fuel in a motor vehicle. 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).

Providers of transportation fuels (referred to as regulated parties) must demonstrate that the mix of fuels they supply meet the LCFS intensity standards for each annual compliance period. They must report all fuels provided and track the fuels' carbon intensity through a system of "credits" and "deficits." Credits are generated from fuels with lower carbon intensity than the standard. Deficits result from the use of fuels with higher carbon intensity than the standard. A regulated party meets its compliance obligation by ensuring that amount of credits it earns (or otherwise acquires from another party) is equal to, or greater than, the deficits it has incurred. Credits and deficits are generally determined based on the amount of fuel sold, the carbon intensity of the fuel, and the efficiency by which a vehicle converts the fuel into useable energy. The calculated metric is tons of GHG emissions. This determination is made for each year between 2011 and 2020. Credits may be banked and traded within the LCFS market to meet obligations.

The proposed regulation provides flexibility for the regulated parties. The regulation is performance-based, and fuel providers have several options. First, they may supply a mix of fuels above and below the standard that, on average, equal the required carbon intensity. Second, they can choose to only provide fuels that have lower carbon intensity than the standard. For example, they may blend low carbon ethanol into gasoline, or renewable diesel fuel in diesel fuel. Third, they may purchase credits generated by other fuel providers to offset any accumulated deficits from their own

[1] For petroleum-based fuels, the lifecycle analysis is also referred to as "well-to-wheels; for fuels produced from crops, the lifecycle analysis is sometimes referred to as "seed-to-wheels."

production. For example, a fuel provider may choose to purchase credits generated from another fuel provider that has banked credits from using electricity in a plug-in hybrid vehicle. Fourth, a fuel provider may bank excess credits generated in a previous year and use those credits when needed. As the objective is to ensure lower carbon intensity fuels are created and used in the California fuels market, the LCFS does not allow the use of credits, or offsets, generated from outside the transportation fuels market.

The LCFS standards established in this rulemaking will be periodically reviewed. The first formal review will occur by January 1, 2012. Additional reviews are expected to be conducted approximately every three years thereafter, or as necessary. The 2012 review will consider the status of efforts to develop low carbon fuels, the compliance schedule, updated technical information, and provide recommendations on metrics to address the sustainable production of low carbon fuels.

To achieve Governor Schwarzenegger's long term goal or reducing GHG emissions by 80 percent by 2050, the carbon intensity of transportation fuels will need to be substantially decreased over the 2020 target of a 10 percent reduction. Therefore, the staff expects to consider targets for the 2030 timeframe in subsequent reviews of the LCFS.

Establishing the LCFS is only one of several important actions needed to reduce GHG emissions from the transportation sector. Additional actions are necessary to fully implement the motor vehicle and other transportation-related GHG measures identified in the Scoping Plan that the Board approved in December 2008.[2] A summary of the transportation-related measures is presented in Table ES -1. The potential benefits of the LCFS have been adjusted assuming that these other measures are implemented.

In addition, the Scoping Plan also identified that, beginning in 2015, transportation fuels are to be included in the Cap and Trade Program. The ARB staff believes that the LCFS is a complementary program to any Cap and Trade Program.

[2] The ARB's approved scoping plan is available at: http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

Table ES-1

Recommended Transportation-Related Greenhouse Gas Reduction Measures Identified in the Air Resources Board's Scoping Plan

Measure	Description	Emission Reductions Counted Towards 2020 Target ($MMTCO_2e$)
Low Carbon Fuel Standard	Reduce the carbon intensity of transportation fuels used in California by an average of 10 percent	15.0
California Light-Duty Vehicle Standards	Implement adopted Pavley standard and planned second phase of the program. Align zero-emission vehicle, alternative and renewable fuel and vehicle technology program with climate change goals.	31.7
Regional Transportation-Related GHG Targets	Develop regional GHG emissions reduction targets for passenger vehicles pursuant to Senate Bill 375.	5
Vehicle Efficiency Measures	Implement light-duty vehicle efficiency measures including properly inflated tires, consideration of minimum fuel-efficient tire standards, and reducing engine load via lower friction oil and reducing the need for air conditioner use.	4.5
Medium/Heavy Duty Vehicles	Adopt medium and heavy-duty vehicle efficiency measure including retrofits to improve the fuel efficiency of heavy-duty trucks by reducing aerodynamic drag and rolling resistance and hybridization of medium-and heavy-duty vehicles.	1.4

Related Federal, State, and International Requirements

There are no similar existing regulations. The Board has established specifications for California reformulated gasoline and California ultra-low sulfur diesel fuel. In addition, the Board has established specifications for a number of alternative fuels used in transportation, such as E85 and natural gas. The staff is currently developing specifications for other alternative fuels, such as biodiesel, and is considering revising other fuel specifications, including natural gas. These actions are complementary to the proposed LCFS rulemaking.

An important goal of the LCFS is to establish a durable fuel carbon regulatory framework that is capable of being exported to other jurisdictions. It is only through the wider adoption of fuel carbon standards that the number of markets in which high-carbon fuels can legally be sold will be reduced. As other areas adopt an LCFS, significant reductions in fuel carbon content will begin to be realized on a global scale. Actions already underway in some jurisdictions outside of California indicate that the LCFS is already perceived as a potential regulatory template: carbon-reduction measures similar to the LCFS are under consideration at the regional, national, and international levels.

At the Federal level, Congress adopted a renewable fuels standard (RFS) in 2005 and strengthened it (RFS2) in December 2007 as part of the Energy Independence and Security Act of 2007 (EISA). The RFS2 requires that 36 billion gallons of biofuels be sold annually by 2022, of which 21 billion gallons must be “advanced” lower carbon biofuels and the other 15 billion gallons can be corn ethanol. Although the RFS2 requires the production of specified volumes of lower carbon biofuels, the fuel carbon intensity reductions it would achieve in California would be substantially below the reductions the LCFS is designed to achieve. The federal RFS would deliver only about 30% of the GHG benefits of the proposed regulation, and does little to incent fuels such as natural gas, electricity or hydrogen. California’s LCFS is designed to complement the federal RFS2.

A regional consortium of eleven Northeastern and Mid-Altantic States has committed to developing an LCFS that is generally based on the same premise as the California LCFS. Significantly, this commitment references California’s efforts to develop an LCFS. Under the commitment, the states will seek to draft a Memorandum of Understanding concerning the development of a regional LCFS program, to be forwarded by December 31, 2009, or as soon thereafter as is possible for each state, for consideration by the Governors of each state. As with the national standard, ARB staff supports the effort to develop an LCFS.

At the international level, the European Parliament adopted, in December 2008, a package of measures to address climate change throughout the European Union. One of these measures is a revised fuel quality directive. This revised directive requires fuel suppliers to reduce GHG emissions, on a lifecycle basis, by up to 10 percent by 2020. Regarding land use change, the European Commission will have to develop a methodology to measure the GHG emissions that result when crops for biofuel production are grown in areas which have previously been used to grow a food crop and this food crop production then moves to other areas which were not is use before. The fuel directive also includes provisions to address sustainability of biofuels production. The need for national and international efforts is critical to ensure that low carbon fuels are not concentrated in any particular area and higher carbon fuels are shuffled to areas that do not have LCFS requirements, or both.

The following sections provide background on the legislative and policy initiatives related to the development of the LCFS, information on the key provisions of the proposed regulation, results of the environmental and economic analyses, and a brief discussion of major public comments. Additional details are presented in the Initial Statement of Reasons: Staff Report - Proposed California Low Carbon Fuel Standard (Staff Report).

Legislative and Policy Directives

The LCFS is supported by a number of legislative and policy directives as presented below. A more detailed discussion is presented in the Staff Report.

- **Assembly Bill 32** - In 2006, the Legislature passed and Governor Schwarzenegger signed Assembly Bill (AB) 32, referred to the California Global Warming Solutions Act of 2006. AB 32 required the Board to develop a plan to reduce GHG emissions in California to 1990 levels by 2020. Among other provisions, AB 32 required the Board to identify and adopt discrete early actions in 2007 and to approve a scoping plan in 2008.

- **Executive Order S-06-06** - In April 2006, Governor Schwarzenegger signed an executive order that established targets to increase the production and use of bioenergy, including ethanol and biodiesel fuels made from renewable resources.[3] One of the executive order provisions specified that, by 2020, 40 percent of biofuels used in the State should be produced in the State. The proposed regulation supports this goal by requiring the use of low carbon alternative fuels and stimulating innovation in the production of these low carbon fuels.

- **Executive Order S-01-07** - In January 2007, Governor Schwarzenegger signed an executive order that established the goal of developing an LCFS to reduce the carbon intensity of transportation fuels by at least 10 percent by 2020 and to consider whether the LCFS should be listed as a discrete early action.[4] In addition, the executive order identified that the LCFS shall apply to all providers of transportation fuels in California, shall be measured on a full fuels cycle basis, and may be met through market-based methods. The proposed regulation satisfies the directive of the executive order.

- **AB 32 Discrete Early Action Measures** - In June 2007, the Board approved the LCFS as a discrete early action measure. The proposed regulation is designed to implement this measure. Table ES-2 summarizes the discrete early action measures and their status.

- **State Alternatives Fuel Plan** - In November 2007, the California Energy Commission and the Board each approved the "State Alternatives Fuel Plan (Fuels Plan)," required pursuant to Assembly Bill 1007.[5] The Fuels Plan presents strategies and actions California must take to increase the use of alternative non-petroleum fuels. An LCFS was anticipated as part of this Plan. The proposed regulation supports and is consistent with the goals of the Fuels Plan.

- **AB 32 Scoping Plan** - In December 2008, the Board approved the AB 32 Scoping Plan to reduce GHG emissions in California to 1990 levels. The Scoping Plan identifies how emission reductions will be achieved from significant GHG sources via regulations, market mechanisms, and other actions. The proposed regulation is listed as one of the key measures in the Scoping Plan.

---

[3] Executive Order S-06-06 is available at: http://gov.ca.gov/executive-order/183/.
[4] Executive Order S-01-07 is available at: http://gov.ca.gov/executive-order/5172/.
[5] The Air Resources Board and the California Energy Commission approved the State Alternatives Fuel Plan in December 2007. The Plan is available at: http://www.energy.ca.gov/ab1007/.

Table ES-2
Status of Discrete Early Action Measures

Measure	Status	Board Hearing Date	Emission Reductions in 2020 $MMTCO_2e$
Green Ports – Cold Ironing Ships at Ports	Adopted	December 2007	0.2
Reduction of High Global Warming Potential Gases in Consumer Products	Adopted	June 2008	0.2
SmartWay Truck Efficiency	Adopted	December 2009	0.9
Reduction of High Global Warming Gases Used in Semiconductor Operations	Adopted	February 2009	0.2
Sulfur Hexafluoride from the Non-Semiconductor and Non-Utility Applications	Adopted	February 2009	0.1
Vehicles Operating with Under-Inflated Tire Pressure	Scheduled	March 2009	0.6
Low Carbon Fuel Standard	Scheduled	April 2009	15.9 *
Landfill Methane Control Measure	Scheduled	May 2009	1.0
Management of High Global Warming Potential Refrigerants	Scheduled	May 2009	11

* Estimated emission reductions based on the "tank-to-wheel" analysis. See Chapter VII.

In support of an LCFS, University of California (UC) Professors Daniel Sperling and the late Alexander Farrell directed a team of UC colleagues that developed two significant reports that provided an initial framework for the LCFS.[6, 7] These two reports established the technical feasibility of an LCFS, identified many of the significant technical and policy issues, and provided a number of specific recommendations. These comprehensive reports were the backbone of ARB staff's initial efforts to develop the LCFS. While not all of the specific recommendations have been incorporated in the LCFS, all of the recommendations have spurred a vigorous debate on the issues and facilitated the development of ARB staff's proposed regulation.

Major Provisions of the Proposed LCFS

The basic framework of the LCFS was presented above. The following discussion provides a more detailed discussion of the proposed regulation. The proposed regulation is presented in Appendix A to this Staff Report.

Fuels Included in the LCFS

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

---

[6] "A Low Carbon Fuel Standard for California, Part 1: Technical Analysis;" Alexander E. Farrell, UC Berkeley, Daniel Sperling, UC Davis, et al; August 1, 2007

[7] "A Low Carbon Fuel Standard for California, Part 2: Policy Analysis;" Alexander E. Farrell, UC Berkeley, Daniel Sperling, UC Davis, et al; August 1, 2007

- California reformulated gasoline;
- California ultralow 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 or types of fuels, but does require regulated parties to comply with an annual standard for the total amount of fuel they provide. This annual standard is expressed as carbon intensity in 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 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.

Under the proposal, 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 the total amount of credits equal or exceed the deficits incurred. Excess credits can be banked or sold to other regulated parties.

A graphical representation of the compliance schedules is presented in Figures ES-1 and ES-2. Table ES-3 shows the compliance schedules for gasoline and diesel fuel.

Figure ES-1

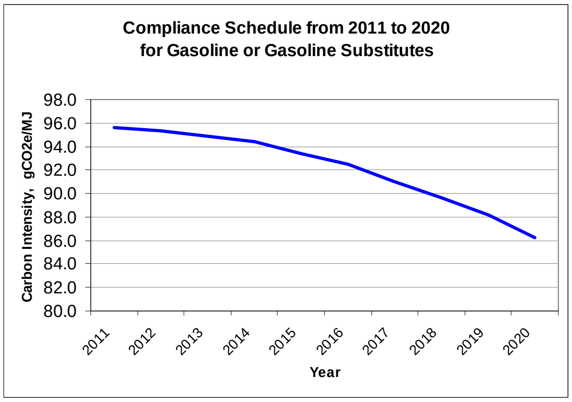


Figure ES-2

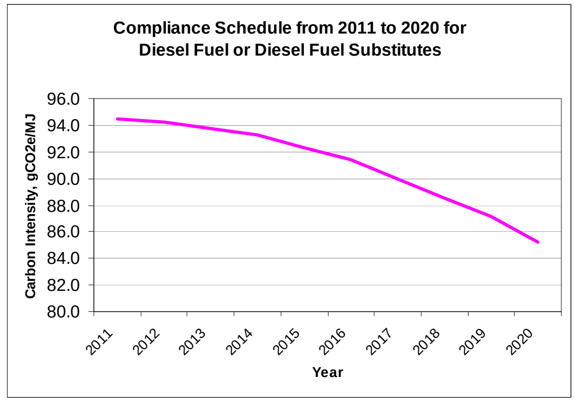


Table ES-3
LCFS Compliance Schedule

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%

Regulated Parties

In general, the regulation places compliance obligations initially on regulated parties that are upstream entities (i.e., producers and importers that are legally responsible for the quality of transportation fuels in California), rather than downstream distributors and fueling stations. However, under specified conditions, the regulated party may be another entity further downstream that can be held responsible for the carbon intensity of the fuels or blendstocks that they dispense in California. The proposed 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. Table ES-4 summarizes the regulated parties for each transportation fuel.

Table ES-4
Regulated Parties Defined in the Low Carbon Fuel Standard

Fuel	Description of the Regulated Party
Gasoline, diesel, and liquid blendstocks (including oxygenates and biodiesel)	The regulated party is the producer or importer of the fuel or blendstocks.
Fossil fuel-derived compressed natural gas (fossil CNG)	The regulated party is generally the utility company, energy service provider, or other entity that owns the fuel dispensing equipment.
Fossil fuel-derived liquefied natural gas (fossil LNG)	The regulated party is the entity that owns the fuel when it is transferred to the fuel dispensing equipment in California.
Other gaseous fuels (biogas/biomethane, hydrogen)	The regulated party will generally be the person who produces the fuel and supplies it for vehicular use.
Electricity	The regulated party will be either the load service entity supplying the electricity to the vehicle or another party that has a mechanism to provide electricity to vehicles and has assumed the LCFS compliance obligation.

Transfer of Compliance Obligations and Regulated Party Status

Certain persons are initially designated as regulated parties who are responsible for all LCFS compliance obligations. Except as provided in the proposal, this status as a regulated party generally remains with the initially designated party even if ownership to the fuel is transferred from one party to another. There are two major exceptions to this general rule. For gasoline and diesel fuel, the compliance obligations would generally transfer to another producer or importer that receives blendstock from the initial regulated party, with provisions for the initial regulated party to retain the compliance obligation if so desired by the affected parties.

The principal rule noted above notwithstanding, the proposal generally allows the regulated party for a fuel to transfer its compliance obligations by written instrument to another party under specified conditions; the buyer or recipient of the transferred fuel, in turn, becomes the regulated party for that fuel. For a variety of reasons, the transfer of such compliance obligations, along with the potential for generating and selling credits, may be desirable for a company, and the proposal allows such transfers.

Voluntary Opt-In Provisions

The proposed regulation includes an opt-in provision and specific exemptions. The proposal explicitly recognizes that certain alternative fuels have full fuel-cycle, carbon intensities (including power train efficiencies) that inherently meet the proposed compliance standards through 2020. As a result, these fuels may choose an opt-in provision. These fuels are:

- Electricity;
- Hydrogen and hydrogen blends;
- Fossil CNG derived from North American sources;
- Biogas CNG; and
- Biogas LNG.

Parties that opt into the LCFS program will be those parties that expect to generate LCFS credits under the regulation. By opting into the program, a person becomes a regulated party under the LCFS regulation and is required to meet the LCFS reporting obligations and requirements. The provisions for opting into the LCFS are set forth in the proposed regulation.

Exemptions

The proposal initially does not apply to regulated parties providing liquefied petroleum gas (LPG or propane). There are also exemptions for specific applications, including racing fuels, interstate locomotives, ocean-going vessels, aircraft, and military tactical vehicles. These sources account for a small amount of the diesel fuel used in California. However, it is important to note that this exemption does not apply to *intra*state locomotives and commercial harborcraft. These sources are already subject to the California standards for diesel fuel. As such, the diesel fuel used in intrastate locomotives and commercial harborcraft would be treated the same as any other transportation fuel subject to the LCFS.

Progress Reporting and Account Balance Reporting

The proposal provides for regulated parties to submit quarterly progress reports by specified dates. These quarterly progress reports are intended to ensure that regulated parties keep track of their ability to comply with the allowable carbon intensity at the end of the annual compliance period. The quarterly reports are required to contain a specified set of information and data, such as carbon intensities, fuel volumes sold or dispensed, fuel transfer information, and other information.

The annual account-balance reporting includes all the information required for the quarterly reporting, along with additional information relating to the total credits and deficits generated during the year or carried over from the previous year; total credits acquired from another party; total credits transferred to other parties; credits generated and banked in the current year; and any deficits to be carried into the next year. All quarterly and annual reporting will be done via a Web-based, interactive form that ARB staff will establish.

Recordkeeping

Regulated parties will be required to maintain specified records in English for a minimum of three years. Upon request by the Executive Officer, regulated parties would need to provide such records within 48 hours, unless a mutual agreement has been reached on an alternative time period.

Evidence of Physical Pathway

To ensure that low carbon fuels that are produced outside of California are actually the source of fuels used in the State, regulated parties will be required to establish physical pathway evidence for transportation fuels subject to the LCFS. For each transportation fuel that a regulated party is responsible for under the LCFS, this could involve a four-part showing:

- A one-time demonstration that there exists a physical pathway by which the transportation fuel is expected to arrive in California. This includes any applicable combination of truck delivery routes, rail tanker lines, gas/liquid pipelines, electricity transmission lines, and any other fuel distribution routes that, taken together, accurately account for the fuel's movement from the generator of the fuel, through intermediate entities, to the fuel blender, producer, or importer in California;
- Written evidence, by contract or similar evidence, showing that a specific volume of a particular transportation fuel with known carbon intensity was inserted into the physical pathway as directed by the regulated party;
- Written evidence, by contract or similar evidence, showing that an equal volume of that transportation fuel was removed from the physical pathway by the regulated party for use as a transportation fuel in California; and
- An update to the initial physical pathway demonstration whenever there are modifications to the initially demonstrated pathway.

Provisions Governing Credits and Deficits and Reconciliation of Shortfalls

Detailed equations and calculations are specified in the proposal for a regulated party to use in calculating its total deficits and credits within each compliance period. A regulated party will meet its annual compliance requirements if its credit balance, at the end of the compliance year, is greater than or equal to zero. Conversely, a regulated party is in deficit and may be in violation if its credit balance is less than zero at the end of a compliance year.

A regulated party whose credit balance is less than zero at the end of a compliance year is in deficit and may be in violation of the LCFS, depending on the magnitude of the shortfall. Shortfalls are categorized into two main categories. First, a regulated party that ends a compliance year with a significant credit balance shortfall, determined on a percentage basis, will be in violation of the LCFS and subject to a notice of violation and penalties commensurate with the size of the violation. In addition, the regulated party must reconcile and remedy the shortfall within a specified period of time. By contrast, a regulated party that ends a compliance year with a relatively small shortfall (i.e., shortfall is 10 percent or less) will be required to reconcile the shortfall within the following year.

It should be noted that, under the proposal, two or more consecutive years in a shortfall will be treated the same as a substantial credit balance shortfall, irrespective of the shortfall's size. A regulated party may generate credits on a quarterly basis, and unused credits may be banked without expiration. A non-regulated third party is prohibited from buying, selling, or trading LCFS credits unless that third party is acting on behalf of a regulated party. There is no prohibition against retiring or exporting LCFS credits to other GHG reduction initiatives, but importing credits from such external programs into the LCFS program would not be allowed.

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 all of the direct 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; and
- Combustion of the fuel in vehicles.

The second part considers any other 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 changes as a significant source of additional GHG emissions. Therefore, staff is proposing that emissions associated with land use changes be included in the carbon intensity values assigned to those fuels in the proposed regulation. 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.

To assess the direct emissions, staff used the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model, modified for use in California (CA-GREET) model as the primary method for calculating carbon intensity values for various transportation fuels. The CA-GREET model is essential a very large spreadsheet that performs accounting of GHG emissions. The CA-GREET model incorporates many specific numeric values that allow for the calculation of the lifecycle GHG emissions associated with producing, transporting, and using various fuels. Staff used CA-GREET to develop specific carbon intensities for a number of different pathways. For some fuels, multiple pathways were developed that represent differences in how and where the fuel is produced.

To assess the emissions from land use changes, staff used a global trade model to estimate the GHG emissions impact. The Global Trade Analysis Project (GTAP) model is discussed in detail in the Staff Report and related Appendices. In general, the model evaluates the worldwide land use conversion associated with the production of crops for fuel production. Different types of land use have different rates of storing carbon. Multiplying the changes in land use times an emission factor per land conversion type results in an estimate of the GHG emissions impacts of land conversions.

The proposed regulation has several different methods for establishing carbon intensities. With these different methods, no fuel is excluded from the LCFS unless specifically exempted.

The first method, referred to as Method 1, establishes default values for a number of specified fuel pathways. Regulated parties may choose to use the default pathways to calculate credits and deficits. The staff is proposing that the Board approve this default Lookup Table. The Lookup Table reflects those fuel pathways that ARB staff has completed to date. The full documentation supporting these carbon intensities is provided on the website. The Lookup Tables are presented in Tables IV-20 and IV-21 in Chapter IV. The various pathways that are completed and proposed for approval in this rulemaking are summarized in Table ES-5.

Note that these pathways do not represent all of the possible pathways for producing fuels. Staff continues to develop carbon intensity values and has released preliminary values for a number of other pathways or is developing carbon intensities for additional pathways. The proposed regulation establishes that the Executive Officer may approve subsequent amendments to the Lookup Table after a specified public process. Table ES-6 summarizes the pathways where preliminary numbers have been developed or that are currently under development. Following a formal public review process as identified in the regulation, the Executive Officer may approve additional carbon intensity values to be added to the Lookup Table.

Also note that the Staff Report presents preliminary estimates for land use changes for biodiesel from soy oil, as well as preliminary estimates for other pathways. These estimates are provided to allow for an assessment of the compliance pathways and are not being proposed for approval at this rulemaking. Like the land use estimates for corn ethanol and sugarcane ethanol, the soy biodiesel land use change result was produced using GTAP. The biodiesel estimate is very preliminary: it does not appear in the LCFS Lookup Table. Its only use has been the preparation of the diesel fuel compliance scenarios appearing in Chapter VI. In particular, staff is concerned that our estimate of land use allocation for co-products may significantly underestimate the land use impacts of soy-based biodiesel, thereby overestimating its GHG benefits. Our ongoing assessment of biodiesel from soy oil may result in a significantly different estimate of its GHG impact. When a value sufficiently robust for use in the regulation has been estimated, that value will be published for public comment and proposed for certification.

Table ES-5
Fuel Pathways Completed for Use in the LCFS

Fuel Pathway	Description of the Pathway
CARBOB (California Reformulated Gasoline Blendstock for Oxygenate Blending)	1 average pathway based on the average crude oil used in California refineries
CaRFG (California Reformulated Gasoline)	1 specific pathway combining CARBOB and a blend of an average Midwestern corn ethanol and California corn ethanol to meet a 3.5% oxygen content by weight (approximately 10% ethanol).
Ethanol from Corn	11 different specific pathways that reflect different options that are used to produce ethanol from corn.
Ethanol from Sugarcane	1 specific pathway for producing ethanol from sugarcane using average production processes.
Electricity	2 specific pathways representing average and marginal electricity used in California.
Hydrogen	4 specific pathways reflecting different options to produce hydrogen as a fuel.
ULSD (Ultra Low Sulfur Diesel)	1 average pathway based on the average crude oil used in California refineries.
Compressed Natural Gas	3 specific pathways reflecting different options to produce compressed natural gas as a fuel.

Table ES-6
Fuel Pathways Under Development for Use in the LCFS

Fuel Pathway	Description of the Pathway
Ethanol from Sugarcane	Brazilian sugarcane using bagasse for electricity production as a co-product credit
	Brazilian sugarcane using mechanized production of sugarcane
Ethanol from Cellulosic Material	Farmed trees using a fermentation process.
	Agriculture waste
	Forest waste
Biodiesel	Midwest soybeans to soy oil for conversion to biodiesel (fatty acid methyl esters - FAME)
	Yellow grease, fats, and waste oil for conversion to biodiesel (FAME)
	Palm oil from South East Asia for conversion to biodiesel (FAME)
Renewable Diesel	Midwest soybeans to soy oil for conversion to renewable diesel.
	Yellow grease, fats, and waste oil using co-fed stream into refinery or bio-refinery for conversion to renewable diesel
Compressed Natural Gas	Remote LNG shipped to Gulfport, Texas; regasified and pipelined to California; CNG in California.
	Remote LNG shipped to Baja, CA; regasified and pipelined to California; CNG in California.
Crude	Derived from oil sands. Derived from oil shale.
Liquefied Natural Gas	Canadian NG via pipeline to LNG liquefaction facility in California; liquefied in CA for use as LNG.
	Remote LNG shipped to Baja, CA; gasified and pipelined to California; liquefied in California for use as LNG.
	Remote LNG shipped to Baja, CA; LNG trucked to California for use as LNG.
	LNG from landfill gas.

Under specified conditions, regulated parties may also obtain Executive Officer approval to either modify the CA-GREET model inputs to reflect their specific processes (Method 2A) or to generate an additional fuel pathway using CA-GREET (Method 2B). For both Method 2A and 2B, there is a scientific defensibility requirement for the regulated party to meet before the Executive Officer can approve new values. For Method 2A, there is an additional provision that requires a substantial change in the carbon intensity relative to the analogous value calculated for that pathway under Method 1.

For CARBOB, gasoline, and diesel fuel, there are specific provisions with regard to the method for determining carbon intensity values, depending on whether the crude oil used to make such fuels is derived from crude oils with high carbon intensity relative to the average carbon intensity of crude oils used in California refineries. Examples include certain crude oils produced from oil sands, oil shale, or other high carbon-intensity crude oils. With regard to CARBOB, gasoline, and diesel fuel made from crude oil extracted from any source other than these high carbon-intensity crude oils, the regulated party would be required to use the carbon intensity specified in the Lookup Table for that fuel.

By contrast, for CARBOB, gasoline, and diesel fuel made from high carbon-intensity crude oil, the regulated party would be required to use the carbon intensity value, if any, which is specified in the Lookup Table for that particular pathway. If there is no carbon intensity value specified for a particular high carbon-intensity crude oil, the regulated party could use Method 2B (with Executive Officer approval) to generate an additional pathway for this type of crude.

Alternately, the regulated party could use the standard Lookup Table value for CARBOB, gasoline, or diesel for fuel derived from non-high carbon intensity crude oil, but only if the regulated party can demonstrate to the Executive Officer that its crude production and transport carbon-intensity value has been reduced to a specified level and meets other specified criteria. To this end, staff is proposing that any regulated party, using a high carbon-intensity crude oil (> 15 g CO_2e/MJ) brought into California that is not already part of the California baseline crude mix, would have to report and use the actual carbon intensity for that crude oil unless the party demonstrates that it has reduced the crude oil's carbon intensity below 15 g CO_2e/MJ using carbon capture and sequestration (CCS) or other method. Upon this demonstration, the regulated party would be permitted to use the average carbon intensity value for the California baseline crude mix (i.e., crude oils currently used in California refineries).

The proposed uses of Method 2A and 2B are subject to public review under the proposal. In other words, the Executive Officer may not approve a carbon intensity value proposed pursuant to Method 2A or 2B unless the proposed method and associated information submitted in support of that method has been disclosed to the public and available for public review for the prescribed time period. Trade secrets, as defined under State law, that are submitted would be treated in accordance with established ARB regulations and procedures (17 CCR §§ 91000-91022) and the Public Records Act (Government Code § 6250 et seq.).

Determination of Vehicle Efficiency Adjustment Factors

In calculating the credits and deficits, factors are used to recognize the fact that some fuels and vehicles are more energy efficient than others. The more energy efficient fuels and vehicles will travel more miles per unit of energy input to the vehicle, thus resulting in less fuel consumption and CO_2 emissions. Total emissions are dependent on both the emissions per unit of energy consumed and the fuel economy of the vehicle.

For example, the well-to-wheel CO_2 emissions from electric vehicles, in units of g CO_2e/MJ of energy delivered to the vehicle, are generally higher than for gasoline vehicles. However, electric vehicles require much less energy to travel a specified distance. As a result of their much lower per mile energy consumption, electric vehicles emit less greenhouse gases than gasoline vehicles on a per mile basis, even though they emit more per unit of energy consumed.

For purposes of the LCFS, staff has adopted the term "Energy Economy Ratio," or EER, to refer to the factor 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 one for diesel-fueled heavy-duty vehicles. The Staff Report and Appendices present examples and data on how the EERs were calculated.

In general, the values for the number of miles driven per unit energy used are based on data or estimates of fuel economy, in units of miles per gallon, and the energy density of the fuel, in units of energy (Btu or Joules) per gallon. However, for advanced technology or emerging vehicles such as battery electric vehicles (BEV), plug-in hybrid electric vehicles (PHEV), fuel cell vehicles (FEV), and heavy-duty compressed natural gas (CNG) or liquefied natural gas (LNG) vehicles, the data are relatively limited. Therefore, the staff has provided EER values that are to be used until such time that there is more robust data available to better establish the EER. Table ES-7 presents the EERs specified in the regulation.

Tables ES–8 and ES-9 presents the adjusted carbon intensities for gasoline and fuels that substitute for gasoline and diesel and fuels that substitute for diesel, respectively. Staff is proposing that the pathways listed in these tables be approved as part of this rulemaking. Note that the carbon intensities in the tables have not been adjusted with the EERs in Table ES-7 to reflect vehicular power train efficiencies.

As there will only be a limited number of these advanced vehicles available in the first few years of the LCFS, the amount of credits generated is not likely to be significantly affected. Staff is committed to review and update these and other EERs as more robust data become available, as well as develop EERs for other vehicles such as internal combustion engines using hydrogen.

Table ES-7
EER Values Proposed for Use in the Low Carbon Fuel Standard

Light- and Medium Duty Applications (Fuels Used in Vehicles Substituting for Gasoline Vehicles)		**Heavy-Duty/Off-Road Applications (Fuels Used in Vehicles Substituting for Diesel Vehicles)**	
Fuel/Vehicle Combination	**EER Values Relative To Gasoline**	**Fuel/Vehicle Combination**	**EER Values Relative to Diesel**
Gasoline (including 6% and 10% ethanol blends) Used In Gasoline Vehicles or 85% Ethanol/15% Gasoline Blends Used In Flexible Fuel Vehicles	1.0	Diesel Fuel Used in A Diesel Vehicle or Biomass-Based Diesel Blends	1.0
Compressed Natural Gas Used in Spark-Ignited Vehicles	1.0	Compressed or Liquefied Natural Gas Used in a Heavy-Duty Spark Ignited or Compression Ignition Engine	0.9
Electricity Used in a Battery Electric or Plug-In Hybrid Electric Vehicle	3.0	Electricity Used in a Battery Electric or Plug-In Hybrid Electric Heavy-Duty Vehicle	3.0
Hydrogen Used in a Fuel Cell Vehicle	2.3	Hydrogen Used in a Heavy Duty Vehicle	1.9

Table ES-8
Adjusted Carbon Intensity Values
for Gasoline and Fuels that Substitute for Gasoline

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
		Direct Emissions	Land Use or Other Effect	Total
Gasoline	CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies	95.86	0	95.86
	CaRFG-CARBOB and a blend of 100% average Midwestern corn ethanol to meet a 3.5% oxygen content by weight (approximately 10% ethanol)	96.09	---	96.09 [1]
	CaRFG-CARBOB and a blend of an 80% Midwestern corn ethanol and 20% California corn ethanol to meet a 3.5% oxygen content by weight blend (approximately 10% ethanol)	95.85	---	95.85 [1]
Ethanol from Corn	Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	69.40	30	99.40
	California; Dry Mill; Wet DGS; NG	50.70	30	80.70
	California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG	65.66	30	95.66
	Midwest; Dry Mill; Dry DGS	68.40	30	98.40
	Midwest; Wet Mill	75.10	30	105.10
	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	77.40
Ethanol from Sugarcane	Brazilian sugarcane using average production processes	27.40	46	73.40
Electricity	California average electricity mix	124.10	0	41.37 [2]
	California marginal electricity mix of natural gas and renewable energy	104.70	0	34.90 [2]
Hydrogen	Compressed H_2 from central reforming of NG	142.20	0	61.83 [3]
	Liquid H_2 from central reforming of NG	133.00	0	57.83 [3]
	Compressed H_2 from on-site reforming of NG	98.30	0	42.74 [3]
	SB 1505 Scenario; Compressed H_2 from on-site reforming with renewable feedstocks	76.10	0	33.09 [3]

[1] Calculated value; land use part of the value
[2] Adjusted by an EER factor of 3.0 to account for power train efficiency improvements over gasoline engines
[3] Adjusted by an EER factor of 2.3 to account for power train efficiency improvements over gasoline engines

Table ES-9
Adjusted Carbon Intensity Values for Diesel and Fuels that Substitute for Diesel

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
		Direct Emissions	Land Use or Other Effect	Total
Diesel	ULSD – based on the average crude oil delivered to California refineries and average California refinery efficiencies	94.71	0	94.71
Compressed Natural Gas	California NG via pipeline; compressed in California	67.70	0	75.22 [1]
	North American natural gas delivered via pipeline; compressed in California	68.00	0	75.56 [1]
	Landfill gas cleaned up to pipeline quality NG; compressed in California	11.26	0	12.51 [1]
Electricity	California average electricity mix	124.10	0	45.96 [2]
	California marginal electricity mix of natural gas and renewable energy	104.70	0	38.78 [2]
Hydrogen	Compressed H_2 from central reforming of NG	142.20	0	74.84 [3]
	Liquid H_2 from central reforming of NG	133.00	0	70.00 [3]
	Compressed H_2 from on-site reforming of NG	98.30	0	51.74 [3]
	SB 1505 Scenario; Compressed H_2 from on-site reforming with renewable feedstocks	76.10	0	40.05 [3]

1 Adjusted by an EER factor of 0.9 to account for power train efficiency losses compared to diesel engine
2 Adjusted by an EER factor of 2.7 to account for power train efficiency improvements over heavy-duty diesel engines
3 Adjusted by an EER factor of 1.9 to account for power train efficiency improvements over heavy-duty diesel engines

Executive Officer Review and Multimedia Evaluations

The proposal would require the Executive Officer to conduct a review of the LCFS implementation by January 1, 2012, the scope and content of which would be determined by the Executive Officer. In addition, staff expects to periodically review the LCFS, likely on a three year schedule. Therefore, the next review would be conducted by January 1, 2015.

Pursuant to Health and Safety Code (H&S) section 43830.8(a), the Board may not adopt a regulation that establishes a specification for a motor vehicle fuel unless a multimedia evaluation for the regulation undergoes the review process specified in the statute. However, this multimedia requirement does not apply if the regulation does not establish a motor-vehicle fuel specification. Based on its assessment as discussed in the Staff Report, staff has determined that the proposed LCFS regulation, by itself, does not establish a motor-vehicle fuel specification and therefore does not trigger a multimedia evaluation requirement under H&S section 43830.8(i).

While the proposal, by itself, does not establish motor-vehicle fuel specifications, we expect that as new, lower-carbon intensity fuels are developed over time, ARB may need to establish fuel specifications to allow the sale of such fuels in California. In those cases, we anticipate the need to conduct multimedia evaluations for the specific fuels. Indeed, ARB has a multimedia evaluation already underway for biodiesel and renewable diesel, for which we hope to establish new fuel specifications in a future rulemaking. Similar multimedia evaluations may be needed if ARB amends the specifications for 85% ethanol gasoline (E-85) and adopts a new biobutanol fuel specification. Therefore, the proposal contains provisions relating to multimedia evaluations which, when applicable, would be conducted pursuant to H&S section 43830.8.

Other Provisions under Consideration

Pursuant to H&S section 38580(b)(3), staff is considering inclusion of a method to convert a violation of any part of this proposed regulation into the number of days in violation, where appropriate, for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26. Staff is also considering language that would enumerate specific acts prohibited under the LCFS.

Pursuant to H&S section 38597, staff is also considering inclusion of a schedule of fees, to be paid by the regulated parties, to fund the use of third-party services. These third-party services would be used to substantiate fuel pathways and other information submitted to the Executive Officer under the LCFS, particularly when the regulated parties are located outside the State. The tracking of credit trades and acquisitions may also be funded by these fees.

Finally, the Staff Report sustainability issues associated with land use changes. Staff will evaluate other issues with regard to the sustainability of alternative fuels. By December 2009, the staff will develop a plan for incorporating sustainability metrics into the LCFS. This plan will be developed through a public process. Issues to be addressed in this process include, among others, a discussion of: the definition of sustainability, what metrics will be reviewed for including the LCFS, a framework for how sustainability metrics will be incorporated and enforced in the LCFS, and a schedule for finalizing sustainability criteria and metrics by no later than December 2011. This effort will involve national and international cooperation.

Possible Compliance Scenarios

In order to determine the feasibility of the LCFS, the staff prepared several scenarios for achieving both the gasoline and diesel standards. Four of the scenarios pertain to gasoline and fuels that can substitute for gasoline, and three pertain to diesel and its substitute fuels. Each scenario describes a compliance path involving a different combination of advanced renewable fuels, and advanced electric and hydrogen-powered vehicles. The compliance scenarios demonstrate that demonstrate that compliance is possible, given what is currently known about the future availability of alternative fuels and vehicles. In addition, the compliance scenarios show that compliance is not contingent upon the availability of only a limited number of alternative fuel-vehicle combinations. Tables ES-10 and ES-11 present a summary of the contribution of various fuels for each of the scenarios.

Table ES-10
Contribution to Reducing the Deficits in the LCFS
For Fuels Substituting for Gasoline Fuel in 2020

Fuel Type	Percent of Reductions Provided by Each Fuel Type Substituting for Gasoline in 2020[1]			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CA Low-CI Ethanol	2	2	2	2
Cellulosic Ethanol	44	43	38	28
Advanced Renewable Ethanol	43	41	36	27
Sugarcane Ethanol	0	3	3	3
Electricity	9	9	18	35
Hydrogen	2	2	3	5

[1] Baseline gasoline consists of 90% CARBOB and 10% Ethanol by volume.

Table ES-11
Contribution to Reducing the Deficits
for Fuels Substituting for Diesel Fuel in 2020

Potential Fuels	Percent of Reductions Provided by Each Fuel Type Substituting for Diesel in 2020		
	Scenario 1	Scenario 2	Scenario 3
CNG	0	2	2
Electricity	0	0	3
Conventional Biodiesel	14	14	13
Advanced Renewable Biodiesel	86	84	81

Environmental Analysis

The environmental analysis of the proposed LCFS regulation focuses on significant decreases in the GHG emissions that would result from the proposed regulation. These reductions would result from production and use of lower carbon transportation fuels in California and changes in the vehicle fleet composition due to new, lower carbon fuels being available to the transportation fuel pool. Staff has estimated the GHG emissions reductions for the combustion of transportation fuels to be about 16 MMT CO_2e by 2020. Staff has also estimated GHG reductions for the full fuel lifecycle, including fuel production through combustion, of 23 MMT CO_2e in 2020. These reductions account for a 10 percent reduction of the GHG emissions from the use of transportation fuel. These reductions compare to the expected 3 percent reduction in GHG emissions if only the federal RFS2 requirements were met.

The proposed LCFS regulation is also expected to result in no additional adverse impacts to California's air quality due to emissions of criteria and toxic air pollutants. Based on the best available data, there may be a benefit in further reducing criteria air pollutants from the 2020 projected vehicle fleet.

To meet the proposed LCFS and the federal RFS2, new biofuel production facilities will likely be built in California. Staff estimates a total of thirty facilities producing corn ethanol (6), cellulosic ethanol (18), and biodiesel (6) could be operational by 2020 based on an assessment of the availability of feedstock material. Biofuel production on a commercial scale will require development of new technologies as well as the continued use of improved conventional technology with crop-derived feedstocks. Non-crop feedstocks could include biomass wastes from municipal solid wastes, agriculture wastes, waste oils, and forestry. Criteria pollutant emissions were estimated for the production of biofuels, the collection of feedstock, and delivery of the finished biofuel.

The emissions estimated for the biofuel production facilities reflect the use of the cleanest energy conversion technologies and air pollution control technologies. ARB staff recommends that the emissions associated with the production of low carbon fuels be fully mitigated consistent with local district and CEQA requirements.

To provide additional information for local districts and to inform the CEQA process, ARB staff is committed to developing a guidance document to provide information on the best practices available to reduce emissions from these types of facilities. This effort will commence immediately; ARB staff plans to have a draft available by the end of December 2009.

The major criteria pollutant emissions are associated with the additional biorefinery truck trips. As part of the analysis, the staff analyzed the localized diesel PM impacts and localized facility emissions impacts.

A health risk assessment was conducted to estimate the potential cancer risk associated with newly established biorefineries based on the facility specific emission inventory and air dispersion modeling predictions. The estimated potential cancer risk levels are associated with onsite diesel PM emissions from three co-located prototype biorefinery facilities. The area with greatest impact was estimated to be the area surrounding the facility fence lines with a potential cancer risk of over 0.4 chances in a million. The health risk assessment also examined combined onsite and offsite emissions of the three prototype biofuel facilities. The area with the greatest impact was estimated with a potential cancer risk of about five chances in a million.

Staff also quantified seven non-cancer health impacts associated with the change in exposure to PM2.5 emissions due to the possible construction and operation of 24 new biofacilities in California. The analysis shows that the statewide health impacts of the emissions associated with these facilities are approximately 24 premature deaths; 8 hospital admissions; and 367 cases of asthma, acute bronchitis and other lower respiratory symptoms.

Staff does not anticipate either a decrease or increase in the emissions from petroleum refineries, power plants, or corn ethanol facilities over the 2010 baseline. The capacity of the State's electric system in 2020 will be sufficient to support 1.8 million electric vehicles due to the 33 percent renewable portfolio standard and off-peak charging.

Also included in the environmental analysis is an examination of other environmental impacts of the LCFS on water quality and use, agricultural resources, biological resources, geology and soils, hazardous materials, mineral resources, and solid waste, among others.

Sustainability provisions will ensure that the LCFS regulation does not adversely impact the ability to continue the use of biofuels and other low carbon intensity fuels in the future. The most critical sustainability component, addressing land use change, is part of the LCFS regulation. To address other sustainability components, both environmental and socioeconomic, will require international cooperation and the development of enforceable certification standards. ARB is committed in the short term to develop a plan to address other sustainability components, and within two years of adoption of the LCFS will develop proposed sustainability criteria.

The ARB is committed to making the achievement of environmental justice an integral part of the LCFS. As such, staff seeks to develop tools to ensure that the proposed regulation does not disproportionately impact low-income and minority communities, does not interfere with the attainment and maintenance of ambient air quality standards, and considers overall societal benefits (such as diversification of energy resources). As part of ongoing AB 32 analysis, ARB staff is developing a screening method for geographically representing emission densities, air quality exposure metrics, and indicators of vulnerable populations, as an evaluation aide for already adversely impacted communities.

Economic Analysis

For the economic analysis of the LCFS, staff estimated the costs of producing the petroleum-based fuels—gasoline and diesel—and the costs of producing the lower-carbon-intensity transportation fuels that could be used in combination with petroleum fuels to meet the LCFS. Staff applied these costs to possible compliance scenarios for both diesel fuel and gasoline. Each of these possible scenarios includes an assumed mix of fuels that satisfies the LCFS reduction targets.

Staff estimated that the displacement of petroleum-based fuels with lower-carbon-intensity fuels will result in an overall savings in the State, as much as $11 billion from 2010 -2020. These savings may be realized by the biofuel producers as profit, or some of the savings may be passed on to the consumers. Should the savings be entirely passed on to consumers, it would represent less than three percent of the total cost of a typical gallon of transportation fuel ($0 - $0.08/gal).

Staff understands that the economic analysis of the LCFS is greatly affected by future oil prices and the actual production costs and timing of lower-carbon-intensity alternative fuels. Economic factors, such as tight supplies of lower-carbon intensity fuels or a lengthy economic downturn keeping crude demand and hence prices down, could result in overall net costs, not savings, for the LCFS.

Staff determined that approximately 25 new biorefineries could be built in California based on an assessment of potential feedstocks. Biofuel producers are expected to eventually recoup their costs through the sale of lower-carbon-intensity fuels, while consumers should see no significant changes in fuel prices to some savings. In addition to liquid fuels, such as ethanol and biodiesel, other lower carbon-intensity fuels, including electricity, hydrogen, and compressed natural gas (CNG) may be used to meet the requirements of the LCFS.

The proposed regulatory action would not affect small businesses because: (1) most, if not all, regulated parties are expected to be relatively large businesses, and (2) small businesses (generally the fueling station owners and operators) would presumably invest in equipment that dispenses LCFS-compliant fuel with the expectation that the costs of such an investment would be recouped through sales of such fuels.

Staff conducted the economic analyses considering all costs of production and distribution of alternative transportation fuels, which, as mentioned above, resulted in overall savings to the State. Staff then recognized that the federal Renewable Fuel Standard (RFS2) will bring significant quantities of ethanol to California, and that the infrastructure required to meet the mandates of RFS2 is essentially the same infrastructure necessary to meet the potential ethanol requirements of the LCFS; therefore, nearly all of the ethanol-related infrastructure costs can be attributed to RFS2.

RFS2 and the proposed LCFS regulation will result in a shift of capital from the petroleum sector to the agricultural, chemical, electricity, and natural gas sectors. This redistribution of capital among these sectors is essential to the success of the LCFS and RFS2. The diversification of California's transportation fuels, which requires a shift of capital from the petroleum sector, is consistent with well-established national and State policies.

The regulation would create costs to the State in the form of lost transportation-fuel taxes, including excise taxes and sales tax. Although there would be no estimated fiscal impact for the first three years of the proposed regulation, staff estimates the potential loss of annual state tax revenue to be $80 million to $370 million in 2020—the year of greatest impact—depending on compliance path(s) chosen. For local government, the impact of sales tax on transportation fuels from implementing the potential compliance scenarios could either create revenue or result in a revenue loss, depending on the compliance path(s) chosen. The impacts to local sales taxes would be location specific. Although there would be no fiscal impact for the first three years of the proposed regulation, staff estimates a potential range of impacts in annual local sales tax revenue of -$51 million to +$2 million from 2013 – 2020.

Enforcement Mechanisms

The ARB is developing a secure on-line LCFS Reporting Tool (LRT) to support the reporting requirements of fuels and other data to the State. ARB plans to have the LRT available for use in early 2010. The LCFS mandates that all regulated parties report required data on a quarterly and annual basis. The LRT will be a secure, web-based data collection and report generation application designed to accommodate submittal of all required information and help regulated parties meet their reporting obligations.

ARB will review the reports submitted via the LRT for completeness and accuracy, evaluate the data in the reports to determine if the regulated party is in compliance with the requirements of the regulation, conduct field investigations and audits of the regulated parties to verify and validate the information submitted in the reports, prepare and issue notices of violation, meet with violators for the purpose of mutual settlement, and participate in litigation if necessary.

Penalties and other remedies for violations of regulations adopted pursuant to AB 32, which includes the LCFS, are set forth in H&SC section 38580 et. seq. These include injunctive relief under H&S section 41513 and criminal and civil penalties under H&S 42400 et seq. and H&S 43025 et seq. Further, H&S section 43029 provides additional penalties designed to eliminate the economic benefits gained from a regulated party's noncompliance.

H&S section 43031(b) states that in determining the amount assessed, the court, the Attorney General, or the state board, in reaching any settlement, shall take into consideration all relevant factors. Those factors include, but are not limited to: (1) the extent of harm to the public health, safety and welfare caused by the violation; (2) the nature and persistence of the violation, including the magnitude of the excess emissions; (3) the compliance history of the defendant, including the frequency of past violations; (4) The preventive efforts taken by defendant, including the record of maintenance and any program to ensure compliance; (5) the innovative nature and the magnitude of the effort required to comply, and the accuracy, reproducibility, and repeatability of the available test methods; (6) the efforts to attain, or provide for, compliance; (7) the cooperation of the defendant during the course of the investigation and any action taken by the defendant, including the nature, extent, and time of response of any action taken to mitigate the violation; and (8) for the person who owns a single retail service station, the size of the business.

Critical Issues and Arguments

Land Use Changes

Carbon intensities are calculated under the LCFS on a full lifecycle basis. This means that the carbon intensity value assigned to each fuel reflects the GHG emissions associated with that fuel's production, transport, storage, and use. In addition to these direct GHG emissions, some fuels create emissions due to indirect land use change effects. An indirect land use change impact is initially triggered when an increase in the demand for a crop-based biofuel begins to drive up prices for the necessary feedstock crop. This price increase causes farmers to devote a larger proportion of their cultivated acreage to that feedstock crop. Supplies of the displaced food and feed commodities subsequently decline, leading to higher prices for those commodities. The lowest-cost way for many farmers to take advantage of these higher commodity prices is to bring non-agricultural lands into production. These land use conversions release the carbon sequestered in soils and vegetation. The resulting carbon emissions constitute the "indirect" land use change impact of increased biofuel production.

Efforts to model indirect land use impacts indicate that the full lifecycle carbon intensities of some biofuels may be similar to or even higher than the carbon intensities of conventional petroleum-based fuels. ARB staff has been and will continue to work with modelers at the University of California and Purdue University to derive indirect land use change estimates that are empirically based, defensible, and fully open to public scrutiny and comment.

Based on the work done to date, crop-based biofuels contribute to some indirect land use impacts. However, the magnitude of this impact has been questioned by renewable fuel advocates. Land use change is driven by multiple factors. Because the tools for estimating land use change are few and relatively new, biofuel producers argue that land use change impacts should be excluded from carbon intensity values pending the development of better estimation techniques. Based on its work with university land use change researchers, however, ARB staff has concluded that the land use impacts of crop-based biofuels are significant, and must be included in LCFS fuel carbon intensities. To exclude them would allow fuels with carbon intensities that are similar to gasoline and diesel fuel to function as low-carbon fuels under the LCFS. This would delay the development of truly low-carbon fuels, and jeopardize the achievement of a 10 percent reduction in fuel carbon intensity by 2020.

Other Indirect Effects

Staff has identified no other significant effects that result in large GHG emissions that would substantially affect the LCFS framework for reducing the carbon intensity of transportation fuels. In addition, stakeholders have not provided any quantitative analysis that demonstrates that these impacts are significant. Providers of crop-based biofuels continue to maintain, however, that significant market-mediated indirect effects other than land use change are likely to exist. Staff will continue to work with interested parties to identify and measure such effects.

Low Carbon Fuel Standard Initiatives Outside of California

Carbon-reduction measures similar to the LCFS are under consideration at the regional, national, and international levels. The most significant of these are summarized in Chapter II. Initiatives such as these are necessary to the achievement of meaningful, long-term fuel carbon reductions: without the wider adoption of fuel carbon standards, fuel producers are free to ship lower-carbon fuels to areas with such standards, while shipping higher-carbon fuels elsewhere. The end result of this fuel 'shuffling' process is little or no net change in fuel carbon content on a global scale. For this reason, ARB seeks to establish a fuel carbon regulatory framework that is durable enough to be exported to other jurisdictions. The successful implementation of an effective framework in one jurisdiction should hasten the adoption of that framework elsewhere.

Meeting the State's 2050 GHG-Reduction Goals

The LCFS is not designed to meet Governor Schwarzenegger's long term goal of reducing GHG emissions by 80 percent by 2050 (Executive Order S-3-05). In order to meet that goal, the downward trend in the carbon intensity of fuels will need to continue following the achievement of the 2020 target of a 10 percent reduction. Therefore, staff plans to consider targets for the 2030 timeframe in future reviews of the LCFS.

Biofuel Production and Food Prices

The U.S. currently has the capacity to produce about 13 billion gallons of corn ethanol annually. Producing this volume of ethanol requires more than 30 percent of America's available corn acreage. Removing that much cropland from food and feed crop production will reduce food supplies and increase prices. Because food prices are determined by multiple factors—including fuel prices—estimating the incremental impact of ethanol production is difficult. As crop-based biofuel production increases, the upward pressure exerted by that production on food prices is likely to also increase. Note, however, that the LCFS is designed to stimulate the production of lower-carbon, non-crop-based fuels. The Federal Renewable Fuels Standard, on the other hand, calls for the production of 15 billion gallons per year of corn ethanol beginning in 2015. Federal biofuel regulations rather than the LCFS, will, therefore, exert the greatest pressure on food prices.

High Intensity Crude Oils

The methods used to extract, refine, and transport some crude oils may result in a relatively high carbon intensity rating for that feedstock. For example, many stakeholders have expressed concern about the increase in crude oil produced from Canadian oil sands. Staff is developing a pathway for petroleum fuels refined from high carbon intensity crude oil, including crude oil from oil sands. The carbon intensity for that pathway will be higher than will the carbon intensity of fuels refined from conventional crude oils. As discussed above, staff is proposing specific regulatory language to address high intensity crude oils that are currently not part of the current California crude oil mix in any significant amount. More details on these provisions are provided in Chapter V.

Impacts on Transportation Fuel Supplies and Prices

Staff has concluded, based on the best available data and fuel price projections presented in the AB 32 Scoping Plan, that the LCFS will not significantly impact either the price or supply of transportation fuels in California. Supplies of biofuel feedstocks appear to be sufficient to sustain the alternative fuel production volumes necessary for LCFS compliance. The staff acknowledges that advances in the production of advanced biofuels are necessary to fully implement both the California LCFS and the federal renewable fuels standard. As such, staff will continue to monitor these issues as implementation of the LCFS occurs over time and will adjust the LCFS standard as necessary to ensure that price and supply disruptions do not occur.

Public Process for LCFS Regulation Development

To support regulatory development, ARB staff initially formed four workgroups to help develop specific provisions or address specific issues. These workgroups are summarized below:

- Policy and Regulatory Workgroup – This workgroup was designed to be the overarching workgroup that would bring together the various overarching issues and address policy considerations. In addition, this workgroup was designed to develop the specific regulatory language.
- Lifecycle Analysis Workgroup – The lifecycle analysis is the heart of the LCFS and was one of the most challenging aspects. This workgroup was designed to be the primary method of vetting results and discussing approaches to the lifecycle analysis.
- Compliance and Enforcement Workgroup – Identifying how the compliance and enforcement mechanisms would be established was the focal point of this workgroup.
- Economic and Environmental Workgroup – The objective of this workgroup was to discuss the economic and environmental analysis.

In practice, the workgroups evolved into a series of public workshops with topics designed to cover the range of issues expected. All of the workgroup meetings were public. The announcements were posted on the ARB website and distributed through a listserve that included over 6,000 recipients. All materials presented at the workshops were also posted on the ARB website. Almost all of the meetings were telecast, available by teleconference, or both. In all, ARB staff held a total of 15 public workshops to support the development of the LCFS. The dates of the workshops and the materials presented at each workshop are available on the ARB website.[8]

In cooperation with Argonne National Laboratories and the California Energy Commission, the ARB staff hosted two special public training sessions on the CA-GREET model used to develop carbon intensities for the various fuel pathways. These sessions, held in the first quarter of 2008, were designed to provide stakeholders with a basic understanding of how the CA-GREET model worked. Training materials on these training sessions is also posted on the ARB website. Additional and very detailed hands-on training for about 10 stakeholders and agency personnel were also provided in the first quarter of 2008.

The ARB staff has also participated in over 200 individual meetings with various stakeholders, supported by numerous individual telephone calls. All comments submitted through the entire process are posted on the ARB website.[9] Over 200 individual comment letters have been submitted either in response to the public workshops or to raise specific issues. In addition, the website contains a number of supporting documents that were related to the development of the LCFS.

Evaluation of Alternatives

Staff evaluated several alternatives to the proposed Regulation. Two of the more significant alternatives are presented below.

1. Take no action at the State level and, instead, defer to the Federal Renewable Fuels Standard. The federal RFS is an important complementary strategy to California's RFS. However, the federal RFS would deliver only about 30 to 40 percent of the GHG benefits of the proposed regulation, and does little to incentivize the development of fuels such as natural gas, electricity, or hydrogen.

2. Implement a gasoline standard only. The LCFS includes separate standards for gasoline and the low carbon fuels that can replace it, and for diesel fuel and its replacements. The Western States Petroleum Association has advocated a gasoline standard only approach to allow for a simpler implementation of the regulation in the early years. ARB does not support this approach. A comprehensive approach from the beginning will allow for the development of a more robust credit market and will provide greater certainty on future

[8] The dates and materials from the ARB workshops are presented at: http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings.htm.
[9] All comments are posted at the following ARB website: http://www.arb.ca.gov/fuels/lcfs/lcfscomm.htm.

expectations. Fuel producers will need to consider overall approaches to providing low carbon transportation fuels. Given the fact that the compliance requirements are substantially less in the early years should provide fuel producers adequate time to develop appropriate compliance options. In addition, failure to include diesel will result in a loss of approximately 20 percent of the LCFS benefits.

Requirements of AB 32

AB 32, at Health and Safety Code section 38560.5, requires that ARB adopt regulations by January 1, 2010, to implement discrete early action GHG emission reduction measures. These measures must "achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions" from the sources identified for early action measures. AB 32 contains additional standards in Health and Safety Code section 38562 that apply to regulations that will be adopted for general emissions reductions consistent with ARB's scoping plan.

In addition, AB 32 requires that the reductions be real, permanent, quantifiable, verifiable, and enforceable. Furthermore, section 38565 requires the Board to "ensure that the greenhouse gas emission reduction rules, regulations, programs, mechanisms, and incentives under its jurisdiction, where applicable and to the extent feasible, direct public and private investment toward the most disadvantaged communities in California and provide an opportunity for small business, schools, affordable housing associations, and other community institutions to participate in and benefit from statewide efforts to reduce greenhouse gas emissions."

Staff believes that the LCFS was developed in accordance with the requirements of AB 32 and the Staff Report presents supporting details. The following provides a brief response to each of the requirements set forth in section 38562 below.

1. Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions.

   The design of the regulation is performance-based to ensure that all fuels that contribute to the goals of the LCFS are treated equitably. The costs and benefits of the measures have been developed to maximize the benefits in consideration of the costs of compliance. The measure has been designed with a compliance schedule that encourages early compliance by allowing the development of credits that can be banked in the early years for future use in the LCFS.

2. Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.

This regulation will provide an over-all GHG and criteria pollutant reduction within the State. There is a potential for additional fuel producing facilities to be built in California and some of these facilities may be proposed for construction in low-income communities. These facilities will be large enough to trigger local permitting and environmental review. To assist in that effort, ARB staff is committed to developing a guidance document to provide information on the best practices available to reduce emissions from these types of facilities, thereby encouraging minimal impact. This effort will commence immediately; ARB staff plans to have a draft available by the end of December 2009.

3. Ensure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions.

   This requirement is not applicable to the proposed regulation.

4. Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.

   The proposed regulation is not expected to adversely affect federal or State ambient air quality standards. This issue has been analyzed and the results are provided within the environmental chapter. Staff expects there to be some increase in local emissions if potential biofuel facilities are constructedin California. These facilities are subject to local permitting and environmental review. See Chapter VII for a detailed discussion of this issue.

5. Consider cost effectiveness of these regulations

   The proposed regulation is expected to result in a net benefit for Californians by reducing fuel consumption and reducing emissions. See Section VIII (Economic Impacts) for a detailed discussion.

6. Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy environment and public health.

   The proposed regulation will provide overall societal benefits by reducing GHG emissions from the transportation fuel pool, decrease our dependence on petroleum, and increase the production of cleaner, low carbon fuel within the state. See Section VII (Environmental Impacts) for a detailed description.

7. Minimize the administrative burden of implementing and complying with these regulations.

The proposed regulation has recordkeeping and reporting requirements for fuel producers that is necessary to ensure compliance. These requirements have been limited to only information that is necessary to demonstrate compliance. See Chapter V for a detailed description of the reporting requirements.

8. Minimize leakage.

   Leakage occurs when an emission limit or regulatory requirement set by the State causes business activities to be displaced outside of California. If leakage were to occur, emissions, jobs and other economic benefits to California would be lost. Leakage is not expected as a result of the proposed regulation. However, the ARB staff encourages the broad adoption of the LCFS in other jurisdictions as the effectiveness of the regulation will be enhanced if there are fewer opportunities to use high-carbon fuels.

9. Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.

   The transportation sector, which includes on-road vehicles, aviation, rail and ships, is the largest contributor to the total statewide GHG emissions inventory, producing approximately 38 percent of the state's total GHGs. Emissions from the transportation sector must be significantly reduced in order to achieve 1990 GHG levels by the year 2020.

   The statewide GHG emission benefits of the proposed regulation are projected to be about 16 $MMTCO_2e$ emissions in 2020. This accounts for approximately 10 percent of the reductions needed to meet the 2020 requirement. See Section VII (Environmental Impacts) for a detailed discussion.

I. Introduction

This Staff Report presents the Air Resources Board's (ARB/Board) basis and rationale for the proposed regulation for the Low Carbon Fuel Standard (LCFS). The LCFS is designed to reduce emissions of greenhouse gases (GHG) by lowering the carbon content of transportation fuels used in California. This Introduction briefly discusses the relationship between greenhouse gases and climate change, outlines the public process used to develop the LCFS, and presents an overview of the Staff Report.

A. Greenhouse Gases and Climate Change

The impacts of climate change on California and its residents are occurring now. Of greater concern are the expected future impacts to the state's environment, public health and economy, justifying the need to sharply cut greenhouse gas emissions.

In the Findings and Declarations for Global Warming Solutions Act of 2006 (AB 32), the Legislature found that:

> *"The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to the marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases asthma, and other health-related problems."*

The Legislature further found that global warming would cause detrimental effects to some of the state's largest industries, including agriculture, winemaking, tourism, skiing, commercial and recreational fishing, forestry, and the adequacy of electrical power.

The impacts of global warming are being felt in California. The Sierra snowpack, an important source of water supply for the state, has shrunk 10 percent in the last 100 years. It is expected to continue to decrease by as much as 25 percent by 2050. World-wide changes are causing sea levels to rise – about 8 inches of increase has been recorded at the Golden Gate Bridge over the past 100 years – threatening low coastal areas with inundation and serious damage from storms.

California is the fifteenth largest emitter of greenhouse gases on the planet, representing about two percent of the worldwide emissions. Carbon dioxide (CO_2) is the largest contributor to climate change. However, AB 32 also references five other greenhouse gases: methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons. Many other gases contribute to climate change.

According to ARB's greenhouse gas inventory, the transportation sector, largely the cars and trucks that move goods and people, is the largest contributor with 38 percent of the State’s total greenhouse gas emissions. If no action is taken to reduce greenhouse gas emissions the transportation sector is expected to increase by 25 percent by 2020, an increase of 46 million metric tons of CO_2e ($MMTCO_2e$).

There are three major contributing components to transportation greenhouse gas emissions: vehicle or engine efficiency, vehicle use, and the carbon intensity of fuels.

Vehicles: Passenger vehicles (cars and light trucks) are responsible for 74 percent of the emissions from the transportation sector and are the primary focus of reductions strategies for the transportation sector. The Pavley (AB 1493) regulation, which the Board has already adopted, requires GHG emission reductions from passenger cars and light trucks. This regulation will provide about 27 $MMTCO_2e$ reductions in 2020 – an 18 percent fleet wide reduction. The U.S. Environmental Protection Agency (U.S. EPA) is currently reconsidering its previous denial of the waiver to implement this measure.

Although the Pavley regulation results in significant GHG reductions, more is needed. Additional strategies are being pursued to ensure that new California vehicles achieve the maximum feasible and cost-effective reductions in GHG emissions, including strengthening GHG tailpipe emission standards from passenger cars and light trucks and improving overall vehicle efficiencies. ARB is also pursuing strategies to increase the efficiency of medium and heavy duty vehicles through both engine specifications and devices that reduce aerodynamic drag and rolling resistance.

Vehicle Use: Another factor in GHG emissions from transportation is the use of the vehicle. In the case of passenger vehicles, the metric for use is most commonly referred to as vehicle miles traveled (VMT). Statewide VMT increased about 35 percent from 1990 to 2007, and with current trends is expected to increase another 20 percent by 2020, and more than double between now and 2040. For California to meet its long term GHG emission reduction goal, this trend must be slowed.

The key to addressing the VMT challenge is providing people with more choices through diversified land use patterns, greater access to alternative forms of transportation including transit, biking and walking, and promoting development patterns where people can work and play without having to drive great distances. Current regional planning efforts are beginning to move in a direction to create choices needed to reverse the projected VMT growth. A strategy of coordinated State, regional, and local land use and transportation planning, policies and finance, must be developed to encourage reductions in VMT, but can also reduce the carbon footprint of developments by reducing land consumption, energy use, water use and waste generation. These strategies are likely to provide modest reductions in GHG emissions by 2020 because of the time required to change land use patterns. In the long term, these strategies are key elements in ensuring that California gets on a low-carbon trajectory as the State gets to and beyond 2020.

Fuel: As indicated above, the fuel used in cars and trucks has a significant impact on emissions. Achieving emissions reductions by reducing the aggregate carbon intensity of fuels can be accomplished through flexible compliance mechanisms. The LCFS applies to all transportation fuel providers, including refiners, blenders, producers or importers of transportation fuels in California and applies to providers of gasoline, diesel, natural gas and propane, electricity, hydrogen, ethanol, biodiesel and other mixed blends. Considering the vast quantities of gasoline and diesel sold per year in California, and that sales of petroleum-based fuels make up almost all transportation fuel sold in California, reducing the carbon intensity of these fuels will provide important environmental and possibly economic opportunities.

B. Public Process for LCFS Regulation Development

To support regulatory development, ARB staff initially formed four workgroups to help develop specific provisions or address specific issues. These workgroups are summarized below:

- Policy and Regulatory Workgroup – This workgroup was designed to be the overarching workgroup that would bring together the various overarching issues and address policy considerations. In addition, this workgroup was designed to develop the specific regulatory language.
- Lifecycle Analysis Workgroup – The lifecycle analysis is the heart of the LCFS and was one of the most challenging aspects. This workgroup was designed to be the primary method of vetting results and discussing approaches to the lifecycle analysis.
- Compliance and Enforcement Workgroup – Identifying how the compliance and enforcement mechanisms would be established was the focal point of this workgroup.
- Economic and Environmental Workgroup – The objective of this workgroup was to discuss the economic and environmental analysis.

In practice, the workgroups evolved into a series of public workshops with topics designed to cover the range of issues expected. All of the workgroup meetings were public. The announcements were posted on the ARB website and distributed through a listserve that included over 6,200 recipients. The materials presented at the workshops were also posted on the ARB website. Almost all of the meetings were telecast, available by teleconference, or both. In all, ARB staff held a total of 15 public workshops to support the development of the LCFS. The dates of the workshops and the materials presented at each workshop are available on the ARB website.[10]

In cooperation with Argonne National Laboratories and the California Energy Commission, the ARB staff hosted two special public training sessions on the CA-GREET model used to develop carbon intensities for the various fuel pathways. These sessions, held in the first quarter of 2008, were designed to provide stakeholders with a basic understanding of how the CA-GREET model worked. Training materials on

[10] The dates and materials from the ARB workshops are presented at: http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings.htm.

these training sessions is also posted on the ARB website. Additional and very detailed hands-on training for about 10 stakeholders and agency personnel were also provided in the first quarter of 2008.

The ARB staff has also participated in over 200 individual meetings with various stakeholders, supported by numerous individual telephone calls. The comments submitted through the entire process are posted on the ARB website.[11] Over 200 individual comment letters have been submitted either in response to the public workshops or to raise specific issues. In addition, the website contains a number of supporting documents that were related to the development of the LCFS.

C. Report Organization

The remaining Chapters of the Staff Report place the development of the regulation in the context of enabling policy and legislative directives, an assessment of the current low-carbon fuels and production technologies, methodologies for determining fuel carbon intensity, likely compliance trajectories that fuel producers might follow, and several other related issues. The following bullets provide thumbnail descriptions of the contents of each Chapter of the report.

- Chapter II reviews the climate-change-related programs the ARB is currently developing, other fuel regulations the Board administers, and climate change programs under development outside of the State.

- Chapter III describes the low-carbon transportation fuels that are likely play a role in the LCFS. The descriptions focus on production processes, and on an assessment of the ability of production technologies to yield significant volumes of low-carbon fuels. For fuels not yet in production, assessments are based on our current knowledge of potential production technologies.

- Chapter IV provides details on the methods ARB uses to determine fuel carbon intensities. The direct, well-to-wheels carbon intensities of all fuels currently covered by the LCFS have been determined using a California-specific version of the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) model. An additional carbon intensity increment for fuels produced from crops is also calculated, using the Global Trade Analysis Project (GTAP) model. This addition increment captures the indirect land us change impacts of biofuel crops. Carbon intensity is measured in units of grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ).

- Chapter V provides a detailed straightforward description of provisions of the LCFS Regulation. This discussion emphasizes what the Regulation requires, and who is obligated to meet each requirement. The actual text of the regulation appears in Appendix A.

[11] All comments are posted at the following ARB website: http://www.arb.ca.gov/fuels/lcfs/lcfscomm.htm.

- Chapter VI presents several potential LCFS compliance scenarios, each showing the specific, year-by-year mix of fuels needed to achieve compliance with the Regulation. One set of scenarios demonstrates four alternative paths toward compliance with the gasoline standard, while another three scenarios demonstrates alternative paths to diesel compliance. The Chapter ends by discussing a series of supplemental scenarios showing the effects of special circumstances and potential modifications to the LCFS: ignoring indirect land use change carbon intensities, allowing light-duty diesel vehicles to earn credits under the gasoline standard, relying entirely (or almost entirely) on ethanol, and others.

- Chapter VII provides an analysis of the environmental impacts of the LCFS. This analysis is designed to comply with the California Environmental Quality Act (CEQA).

- Chapter VIII presents the economic analysis. The analysis presents the costs of compliance based on the compliance scenarios identified in Chapter VI.

- Chapter IX describes the enforcement mechanisms that ARB will employ to achieve compliance on the part of regulated parties.

- During the course of developing the LCFS, ARB staff considered a wide range of policy mechanisms for achieving the mandated fuel carbon intensity reduction. Chapter X discusses alternative approaches and addresses staff's rationale for rejecting the alternative approaches in favor of the approach that was eventually adopted.

Finally, there are a number of appendices supporting the Staff Report. These appendices provide additional details supporting the various Chapters.

This Page Left Intentionally Blank

II. Government Programs Affecting Transportation Fuels

This Chapter provides a summary of the various programs that affect transportation fuels and specifically the development of California's LCFS. These programs broadly include legislative actions, regulations, policies, or initiatives that have effects on the development of the LCFS. These include programs initiated in California, on the national level, and the international level.

This Chapter is organized as follows:

- California programs to reduce GHG emissions;
- California fuels regulations;
- California incentive programs for transportation fuels;
- Federal renewable fuels program; and
- Other transportation fuel and LCFS initiatives.

A. California Programs to Reduce Transportation-Related GHG Emissions

There are a number of programs that are designed to reduce GHG emissions that affect the development of the LCFS. Early programs, such as the GHG standards for passenger cars and the State's Alternative Fuels Plan, established baselines and important background for the LCFS. Other programs include Assembly Bill (AB) 32, the Global Warming Solutions Act of 2006 and subsequent actions taken to implement this bill, and various executive orders issued that established the low carbon fuel standard and set statewide goals for the production of biofuels in California. These programs are discussed in this section.

1. Early Climate Change Work

a. AB 1493 – Pavley GHG Emission Standards for Cars

In 2002, Assemblywoman Fran Pavley authored Assembly Bill (AB) 1493. This bill authorized the Board to adopt regulations to reduce GHG from passenger vehicles. In September 2004, the Board adopted the implementing regulation, designed to be effective beginning 2009. This regulation is often referred to as the "Pavley" or "AB 1493" regulation. The regulation would reduce GHG emissions from California passenger vehicles by about 22 percent by 2012 and about 30 percent by 2016. The regulations were stalled by automaker lawsuits and the U.S. EPA's refusal, under the previous administration, to grant California an implementation waiver. President Obama recently ordered the U.S. EPA to reconsider its denial of California's request for a waiver. Staff now assumes the Pavley regulation will be implemented. Therefore, the emission benefits of those regulatory changes are included in the baseline for purposes of the LCFS analyses. The Pavley regulation and the LCFS are two critical components of California's work to reduce GHG from transportation sources.

b. AB 1007 – State Alternative Fuels Plan

Assembly Bill 1007 (Pavley, Statutes of 2005) directed the California Energy Commission (CEC) and the ARB to develop a State Alternative Fuels Plan (Plan) to increase the use of alternative fuels. The Plan, jointly approved in 2007, recommended a strategy that combines private capital investment, financial incentives, and technology advancement approaches.(1) The Plan also highlighted the need to:

- Promote alternative fuel blends with gasoline and diesel in the near and mid term and stimulate innovation through the development of a low-carbon fuels standard;
- Maximize alternative fuels in early adopter market niches, such as heavy-duty vehicles, fleets, off-road vehicles, and ports;
- Maximize use of alternative fuels in internal combustion engines and develop new transportation technologies, such as electric drive and hydrogen fuel cells, in the mid-to-long term;
- Maximize the use of mass transit, encourage smart growth and land use planning to help reduce vehicle miles traveled and vehicle hours traveled; andI
- Improve vehicle efficiency to reduce the total energy needed to power transportation in California.

The Plan highlighted a number of strategies that could be used to promote the development and use of alternative fuels in California and provided a sound basis upon which to develop the LCFS. In addition, the Plan was based on full fuel lifecycle analyses. This early work on lifecycle analysis was a critical starting point for the development of the lifecycle analyses done for the LCFS.

2. Executive Order S-01-07 – Low Carbon Fuel Standard

In January 2007, Governor Schwarzenegger issued Executive Order S-01-07 calling for a low carbon fuel standard for transportation fuels to be established for California.(2) This Executive Order was thus the genesis of the proposed regulation proposed in this Staff Report. The Executive Order calls for a reduction of at least 10 percent in the average carbon intensity of California's transportation fuels by 2020.

The Executive Order specifies that the LCFS shall apply to all refiners, blenders, producers, or importers (providers) of transportation fuels in California. It also states that the LCFS shall be measured on a full fuels cycle basis, and may be met through market-based methods by which providers exceeding the performance required by an LCFS shall receive credits that may be applied to future obligations or traded to providers not meeting the LCFS.

The Executive Order instructs the California Environmental Protection Agency to coordinate activities between the University of California, the California Energy Commission (Energy Commission) and other State agencies to develop and propose a draft compliance schedule to meet the 2020 target. Furthermore, it directed ARB to consider initiating a regulatory proceeding to establish and implement the LCFS.

In support of the LCFS and as directed in the Executive Order, University of California (UC) Professors Daniel Sperling and the late Alexander Farrell directed a team of UC colleagues that developed two significant reports that provided an initial framework for the LCFS.(3, 4) These two reports established the technical feasibility of an LCFS, identified many of the significant technical and policy issues, and provided a number of specific recommendations. These comprehensive reports were the backbone of ARB staff's initial efforts to develop the LCFS. While not all of the specific recommendations have been incorporated in the LCFS, all of the recommendations have spurred a vigorous debate on the issues and facilitated the development of ARB staff's proposed regulation.

3. Other Executive Orders and Legislation

a. Executive Order S-06-06 – State Bioenergy Action Plan

Executive Order S-06-06 directed various State agencies to work together as part of the Bioenergy Interagency Working Group to promote the development and use of biomass resources in California.(5) Among other provisions, the Executive Order lists targets to increase the production and use of bioenergy, including the production and use of ethanol and biodiesel fuels made from renewable resources. Key targets for biofuels and bioenergy are presented below:

- The State produces a minimum of 20 percent of its biofuels, including ethanol and bio-diesel fuels made from renewable sources, within California by 2010, 40 percent by 2020, and 75 percent within California by 2050; and

- The State meets a 20 percent target within the established State goals for renewable power generation for 2010; and 2020.

If these goals are met, they would ensure that a significant portion of the biofuels used in the LCFS are produced in California. The 20 percent renewable power generation requirement would provide lower carbon intensity electricity, including electricity used for transportation under the LCFS.

Currently, there is production capacity for ethanol and biodiesel in the State totaling about 485 million gallons. About 87 percent of this total is ethanol produced from corn, with the balance being biodiesel produced from yellow grease and waste oils. There is over 300 million gallons of ethanol capacity that is either constructed, but idle, or is permitted but not constructed. The total consumption of ethanol and biodiesel use in the State in 2010 is estimated to be about 1.45 billion gallons. Therefore, the 2010 target should be met, but additional capacity will be needed to meet the 2020 target.

The California Energy Commission estimates that approximately 12 percent of California's retail electricity is currently met with renewable energy resources. Renewable energy includes, but is not limited to, wind, solar, geothermal, small hydroelectric, biomass, anaerobic digestion, and landfill gas. Electricity from renewables is required to be 20 percent of total electricity generated by 2010 per California's current Renewables Portfolio Standard (RPS).

Increasing the use of renewable energy sources will decrease California's reliance on fossil fuels, thereby reducing GHG emissions from the electricity sector. Per Governor Schwarzenegger's order for a 33 percent RPS, it is anticipated that California will have 33 percent of its electricity provided by renewable resources by 2020.

b. SB 1505 – Environmental Standards for Hydrogen

Senate Bill (SB) 1505 (Lowenthal, 2006) called for the Board to adopt regulations regarding environmental standards for hydrogen production. The bill requires that emissions associated with hydrogen used as a vehicle fuel must be lower than baseline gasoline values. Emissions values of oxides of nitrogen (NO_x) plus reactive organic compounds (ROG) and toxic air contaminants (TAC) associated with hydrogen production are to be compared on a well-to-tank basis to the "average motor gasoline." Emissions of greenhouse gases are to be compared on a well-to-wheels basis to the "average new gasoline vehicle." The bill also requires that one third of the hydrogen must be made from eligible renewable resources.

ARB staff is currently developing the regulation setting the environmental and energy standards for hydrogen production. Information on this rulemaking can be found at the following website: http://www.arb.ca.gov/msprog/hydprod/hydprod.htm. The proposed requirements will be in effect for State-funded hydrogen stations once the regulation is adopted, and for hydrogen stations in California upon reaching a statewide annual throughput of 3,500 metric tons. As part of SB 1505, the ARB would require providers of hydrogen fuel for transportation in the State to report annual amount of hydrogen dispensed.

SB 1505 is important to the LCFS because it will ensure that hydrogen fuel produced at state-funded stations (as most are expected to be) has lower carbon intensity than gasoline and is one-third renewable.

4. California Global Warming Solutions Act of 2006 – AB 32

In September 27, 2006, Governor Schwarzenegger signed AB 32, the Global Warming Solutions Act of 2006 (Nuñez, Chapter 488, Statutes of 2006). This landmark bill establishes a first-in-the-world economy-wide program of regulatory and market mechanisms to achieve real, quantifiable, cost effective reductions of greenhouse gases. ARB is the lead agency for implementation.

AB 32 requires the ARB to establish a statewide GHG emissions cap for 2020, adopt GHG reporting rules, adopt a plan to reduce GHG emissions (the Scoping Plan), and to adopt a list of discrete early action measures to reduce GHG. AB 32 formally established California's climate change program, of which the LCFS is a part.

The following subsections highlight the key AB 32 actions relevant to the LCFS.

a. Climate Change Early Actions

Under AB 32, ARB is required to identify and adopt regulations for discrete early actions that could be enforceable on or before January 1, 2010. In 2007, the Board identified nine discrete early action measures. In addition to this LCFS, the measures included regulations high global warming gases in various uses, port operations, heavy duty truck efficiency, tire inflation, and landfills. Table II-1 lists the discrete early action measures and their status.

Table II-1
Status of Discrete Early Action Measures

Measure	Status	Board Hearing Date	Emission Reductions in 2020 $MMTCO_2e$
Green Ports – Cold Ironing Ships at Ports	Adopted	December 2007	0.2
Reduction of High Global Warming Potential Gases in Consumer Products	Adopted	June 2008	0.2
SmartWay Truck Efficiency	Adopted	December 2009	0.9
Reduction of High Global Warming Gases Used in Semiconductor Operations	Adopted	February 2009	0.2
Sulfur Hexafluoride from the Non-Semiconductor and Non-Utility Applications	Adopted	February 2009	0.1
Vehicles Operating with Under-Inflated Tire Pressure	Scheduled	March 2009	0.6
Low Carbon Fuel Standard	Scheduled	April 2009	15.9 *
Landfill Methane Control Measure	Scheduled	May 2009	1.0
Management of High Global Warming Potential Refrigerants	Scheduled	May 2009	11

* Estimated emission reductions based on the "tank-to-wheel" analysis. See Chapter VII.

As the table shows, all of the measures are on schedule to be adopted prior to the January 1, 2010 implementation date. From a GHG emission reduction perspective, the LCFS is a major GHG emission reduction measure, accounting for over 50 percent of the total emission reductions from the discrete early action measures.

b. Climate Change Scoping Plan

In December 2008, the Board approved the Climate Change Scoping Plan.(6) The Scoping Plan is the State's roadmap to reach the greenhouse gas reduction goals in AB 32. Reducing greenhouse gas emissions levels to 1990 levels means cutting approximately 30 percent from business-as-usual emissions levels projected for 2020, or about 15 percent from today's levels. The Scoping Plan identified a number of recommended actions necessary to achieve the goals of AB 32. In addition to a specific action to develop the LCFS, the Scoping Plan identified other actions that would impact the LCFS. These are highlighted below:

- Light-Duty Vehicle Greenhouse Gas Standards: As discussed above, the Pavley regulations are an important measure to reduce GHG emissions. In addition to the existing measure, the Scoping Plan identifies a planned second phase of the program that would align the zero-emission vehicle program, alternative and renewable fuel and vehicle technology program with long-term climate change goals to achieve additional GHG emission reductions. These strategies are referred to as Pavley II. Collectively, Pavley I and II are expected to achieve 31.7 $MMCO_2e$ in 2020.

- Regional Transportation-Related GHG Targets: In September 2008, Governor Schwarzenegger signed Senate Bill 375 (Steinberg, 2008). SB 375 establishes regional targets for reducing passenger vehicle GHG emissions. ARB is working with the metropolitan planning organizations in the State to align their regional transportation, housing, and land-use plans and prepare a Sustainable Communities Strategy (SCS) to reduce the amount of vehicle miles traveled in respective regions and demonstrate a region's ability to attain its greenhouse gas reduction targets. ARB must propose draft targets by June 10, 2010, for the purpose of reducing greenhouse gas emissions from passenger vehicles, and adopt final targets by September 30, 2010. Overall, the Scoping Plan estimated that the measure could achieve 5 $MMTCO_2e$ in 2020.

- Light-Duty Vehicle Efficiency Measures: The Scoping Plan identifies several measures to reduce light-duty vehicle GHG emissions. These measures include properly inflated tires, consideration of minimum fuel-efficient tire standards, and reducing engine load via lower friction oil and reducing the need for air conditioner use. Collectively, these measures are targeted for 4.5 $MMTCO_2e$ in 2020.

- Medium/Heavy Duty Vehicle Efficiency Measures: The Scoping Plan also identifies several measures to improve the efficiency of medium- and heavy-duty vehicles. These measures include retrofits to improve the fuel efficiency of heavy-duty trucks by reducing aerodynamic drag and rolling resistance and hybridization of medium- and heavy-duty trucks. These measures are targeted for 1.4 $MMTCO_2e$ in 2020.

These measures are all significant to the LCFS because they affect estimates of the amount of fuel used in 2020. To ensure that the LCFS does not double count emission reductions, these measures have all been accounted for in the LCFS. Additional information on these adjustments is presented in subsequent chapters.

In addition to these measures, the recommended action in the Scoping Plan to develop a California Cap and Trade Program is relevant to the LCFS. The cap and trade program provides a firm cap on 85 percent of the State's greenhouse gas emissions. Sectors under the cap must reduce their emissions. Sectors under the cap starting with the first compliance period include electricity generation, oil production operations, and petroleum refineries. Transportation fuel is not presently under the cap, but will be brought under the cap beginning in 2015. Additional discussion on the relationship between the LCFS and the cap and trade program is presented in Chapter V.

B. California Fuels Programs

The following section provides a brief overview of California's reformulated gasoline regulations, a description of the California Predictive Model, and the impacts of adding ethanol to gasoline. The LCFS is a complementary measure to these regulations.

1. Phase 2 California Reformulated Gasoline

The California Clean Air Act requires the ARB to adopt regulations that produce the most cost-effective combinations of control measures on motor vehicles and motor vehicle fuels. This directive led to many actions, including the Board approval of the Phase 2 California Reformulated Gasoline (CaRFG2) regulations in 1992.[12] The CaRFG2 regulations set stringent standards for California gasoline that produced cost-effective emission reductions in new and in-use gasoline-powered vehicles. The regulations set specifications for the following eight fuel properties:

- Sulfur;
- Aromatic hydrocarbon content;
- Oxygen content;
- Benzene content;
- 50 Percent distillation temperature;
- 90 percent distillation temperature;
- Olefin content; and
- Reid vapor pressure.

With the exception of oxygen, the regulations set three limits for each property: a ”cap” limit that applies to all gasoline anywhere in the gasoline distribution and marketing system and does not vary; and “flat” and “averaging” limits that apply to gasoline when it is released by refiners, importers, and blenders (collectively, “producers”).[13] For oxygen, the regulations establish a range of flat limits and caps that may vary depending on the location and the specific fuel formulation.

[12] For additional information on the Phase 2 reformulated gasoline regulations, see the following website: http://www.arb.ca.gov/fuels/gasoline/carfg2/carfg2.htm

[13] For fuels regulations, we generally use producers to represent those that are affected by the regulations. The specific regulations, however, have requirements that sometimes differ depending on whether the affected entity is a refiner, importer, or blender. The reader is referred to the regulations for specific applicable requirements.

Gasoline producers could comply with the limits in one of three ways. First, for a given property, each producer may choose to meet either the flat limit or the averaging limit. Second, a producer may use the Predictive Model to identify other sets of property limits (flat, averaging, or mixed) that can be applied to that producer's gasoline. Third, a producer may validate an alternative set of property limits through emission testing per a prescribed protocol. Whether validated by the Predictive Model or by testing, no alternative limit may exceed the cap limit for the property.

To comply with the oxygen content requirement, producers generally chose to use methyl-tertiary-butyl-ether (MTBE). Soon after CaRFG2 implementation, the presence of MTBE in groundwater began to be reported. An investigation and public hearings were conducted resulting in the issuance of Executive Order D-5-99 on March 25, 1999.(7) The Executive Order directed the phase-out of MTBE in California's gasoline. In addition, the Legislature passed Senate Bill 989. Among other provisions, the bill directed the ARB to ensure that regulations adopted pursuant to the Executive Order maintain or improve upon emissions and air quality benefits achieved by CaRFG2 as of January 1, 1999 (Health and Safety Code section 43013.1).

2. Phase 3 California Reformulated Gasoline

In response to the Governor's and Legislature's directive, the Board approved the Phase 3 California Reformulated Gasoline (CaRFG3) regulations on December 9, 1999 and amended them on July 25, 2002.[14] The CaRFG3 regulations prohibited California gasoline produced with MTBE starting December 31, 2003, established revised CaRFG3 standards, established a CaRFG3 Predictive Model, and made various other changes. The CaRFG3 regulations also placed a conditional ban, starting December 31, 2003, on the use of any oxygenate other than ethanol, as a replacement for MTBE in California gasoline.

On June 14, 2007, the Board approved amendments to the CARFG3 regulations as summarized below:

- Amend the California Predictive Model to ensure that permeation emissions associated with ethanol use are mitigated and to incorporate new data;
- Add an option to use an alternative emissions reduction plan (AERP) for a limited time period to help mitigate permeation emissions;
- Decrease the sulfur cap limit from 30 parts per million by weight (ppmw) to 20 ppmw to improve enforceability and facilitate new motor vehicle emissions control technology;
- Allow emissions averaging for low level sulfur blends to provide additional flexibility for producers;

[14] For additional information on the Phase 3 reformulated gasoline regulations, see the following website: http://www.arb.ca.gov/fuels/gasoline/carfg3/carfg3.htm.

- Apply the 7.00 psi RVP limit to oxygenated gasoline to reflect that virtually all gasoline will be oxygenated and commingling emissions are not a problem for these fuels; and retain the 6.90 RVP limit for non-oxygenated gasoline to ensure that no increase in hydrocarbon emissions from commingling with oxygenated gasoline will occur;
- Allow flexibility in setting oxygen content in the Predictive Model to account for variability in test methods;
- Increase the maximum allowable amount of denaturant in ethanol to be consistent with new federal requirements;
- Update the test method for oxygenate content of gasoline;
- Require producers to use the revised Predictive Model starting December 31, 2009, with the AERP as a mitigation option; and
- Require the production of gasoline that is compliant with the revised Predictive Model beginning December 31, 2011.

The current specifications for CaRFG3 are presented in the Table II-2.

Table II-2
Current California Reformulated Gasoline Standards

Property	Flat Limits	Averaging Limits	Cap Limits
Reid Vapor Pressure[1] (psi)	7.00 or 6.90[2]	NA	6.40 -7.20
Sulfur Content (parts per million by weight)	20	15	60[3]
			30[3]
			20[3]
Benzene Content (% by volume)	0.80	0.70	1.10
Aromatics Content (% by volume)	25.0	22.0	35.0
Olefins Content (% by volume)	6.0	4.0	10.0
T50 (degrees Fahrenheit)	213	203	220
T90 (degrees Fahrenheit)	305	295	330
Oxygen Content (% by weight)	1.8 – 2.2	Not Applicable	1.8[4]-3.5[5]
			0[4] - 3.5[5]
Methyl tertiary-butyl ether (MTBE) and oxygenates other than ethanol	Prohibited as provided in § 2262.6	Not Applicable	Prohibited as provided in § 2262.6

1 The Reid vapor pressure (RVP) standards apply only during the warmer weather months identified in section 2262.4.
2 The 6.90 pounds per square inch (psi) flat limit applies when a producer or importer is using the CaRFG Phase 3 Predictive to certify a final blend not containing ethanol. Otherwise, the 7.0 psi limit applies.
3 The CaRFG Phase 3 sulfur content cap limits of 60, 30, and 20 parts per million are phased in starting December 31, 2003, December 31, 2005, and December 31, 2011, respectively, in accordance with section 2261(b)(1)(A).
4 The 1.8 percent by weight minimum oxygen content cap only applies during specified winter months in the areas identified in section 2262.5(a).
5 If the gasoline contains more than 3.5 percent by weight oxygen from ethanol but no more than 10.0 volume percent ethanol, the maximum oxygen content cap is 3.7 percent by weight.

3. California Reformulated Diesel

In November 1988, the Board approved regulations limiting the allowable sulfur content of motor vehicle diesel fuel to 500 parts per million by weight (ppmw) statewide and the aromatic hydrocarbon content to 10 percent by volume with a 20 percent limit for small refiners.[15] These diesel fuel regulations, which became effective in 1993, are a necessary part of the State's strategy to reduce air pollution through the use of clean fuels and lower-emitting motor vehicles and off-road equipment. The regulation limiting the aromatic hydrocarbon content of diesel fuel has included provisions that enable diesel fuel producers and importers to comply through alternative diesel formulations that may cost less. The alternative specifications must result in the same emission benefits as the 10 percent aromatic standard (or in the case of small refiners, the 20 percent standard).

On July 24 2003, the Board approved amendments to the California diesel fuel regulations. The amendments reduced the sulfur content limit from 500 ppmw to 15 ppmw for diesel fuel sold for use in California in on-road and off-road motor vehicles starting in mid-2006. The lower sulfur limit aligned the California requirement with the on-road diesel sulfur limit adopted by the U.S. EPA. However, the California sulfur requirement applies to on and off-road motor vehicle diesel fuel. The new sulfur standard enabled the use of the emissions control technology required to ensure compliance with the new emissions standards adopted by the U.S. EPA for 2007 and subsequent model-year heavy-duty engines and vehicles.

In 2005, the Board also adopted a measure that applied the diesel fuel standards to harborcraft and intrastate locomotives.

4. California Standards for Alternative Fuels

"Alternative fuel" generally means any motor vehicle transportation fuel that is not gasoline or diesel fuel. This includes, but is not limited to, those fuels that are commonly or commercially known or sold as one of the following: M-100 fuel methanol, M-85 fuel methanol, E-100 fuel ethanol, E-85 fuel ethanol, biodiesel, compressed natural gas (CNG), liquefied natural gas (LNG), liquefied petroleum gas (LPG), or hydrogen. For purposes of the LCFS regulation, alternative fuels also include electricity for motor vehicle transportation use, but there are currently no quality specifications in the State for electricity used as a motor vehicle fuel.

With exceptions as discussed below, the quality of alternative motor vehicle fuels is subject to composition specifications under title 13, California Code of Regulations (CCR), sections 2291.1 through 2292.7, as follows:

- M-100 fuel methanol (13 CCR §2292.1);

[15] For additional information on California reformulated diesel, see the following website: http://www.arb.ca.gov/fuels/diesel/diesel.htm.

- M-85 fuel methanol (13 CCR §2292.2);
- E-100 fuel ethanol (13 CCR §2292.3);
- E-85 fuel ethanol (13 CCR §2292.4);
- Compressed natural gas (13 CCR §2292.5);
- Liquefied petroleum gas (13 CCR §2292.6); and
- Biodiesel specifications (13 CCR§2292.7 – Under development).

For E-85, the Division of Measurement Standards (DMS) adopted a specification for E-85 in 4 CCR §4145 (effective May 22, 2004). More recently, ASTM updated its specification for E-85 in D5798-07, "Standard Specification for Fuel Ethanol (Ed75-Ed85) for Automotive Spark-Ignition Engines." [16] Because the newer ASTM specification better reflects current technologies, ARB plans to update its E-85 specifications in a rulemaking tentatively scheduled for Board consideration in late 2009.

Liquefied natural gas is converted to CNG in LNG vehicles prior to being supplied to the engine for combustion. Therefore, the fuel used in LNG vehicles is subject to the CNG motor vehicle fuel specifications cited above.

In 2005, Senate Bill 76 (SB 76, Stats. 2005, ch. 91) placed the responsibility to adopt specifications for hydrogen fuel on DMS. This law required DMS to have the standards in place on or before January 1, 2008. The DMS is required to adopt by reference the latest standards for hydrogen established by an American National Standards Institute (ANSI) accredited, standards-development organization. If such a standard has not been developed, DMS is required to develop interim standards.

Pursuant to SB 76, DMS determined that no ANSI-accredited, standards-development organization had established standards for hydrogen fuel used in fuel cell or internal combustion motor vehicles before 2008. Therefore, DMS promulgated interim standards for hydrogen fuel to be used in fuel cell or internal combustion vehicles. The DMS standards are set forth in 4 CCR §§4180 and 4181 and became effective September 11, 2008.

Biodiesel is considered to be an alternative fuel, but there are currently no ARB standards for biodiesel. Until recently, biodiesel blendstock (B-100) and biodiesel blends were subject to the specifications promulgated by DMS and set forth in 4 CCR §4147 (effective August 8, 2004). However, DMS is required by law to adopt by reference the latest standards established by a recognized consensus organization or standards writing organization, such as ASTM or the Society of Automotive Engineers (SAE). [17]

In June 2008, ASTM adopted three biodiesel specifications. First, ASTM updated its specification for B-100 blendstock, D6751-08, "Standard Specification for Biodiesel Fuel

---

[16] ASTM International, formerly known as the American Society for Testing and Materials (ASTM).
[17] Business And Professions Code sections 13450-13451.

Blend Stock (B100) for Middle Distillate Fuels." Second, ASTM approved revisions to D975-08, "Standard Specification for Diesel Fuel Oils," which would subject biodiesel blends from B-1 to B-5 to the same specification as regular diesel fuel. Finally, ASTM adopted new specifications for B-6 to B-20 in D7467-08, "Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20)."

As noted, the 2008 ASTM specifications for biodiesel and biodiesel blends cited above are the standards that currently apply to such fuels sold in the State. However, staff plans to consider a rulemaking for adopting new biodiesel specifications for motor vehicle fuel, which is currently calendared for late 2009. In support of that effort, staff is currently conducting a multimedia evaluation of biodiesel and renewable diesel pursuant to H&S §43830.8. Also, if necessary, an emissions test program is being conducted to evaluate potential alternative specifications that would result in biodiesel having the same emission characteristics as diesel complying with 13 CCR sections 2281-2285 and 2299.

C. California Incentive Programs for Transportation Fuels

Two recent California incentive programs affect alternative fuels. These are the Alternative Fuel Incentive Program (AB 1811) and the California Alternative and Renewable Fuel, Vehicle Technology, Clean Air, and Carbon Reduction Act of 2007 (AB 118). These programs are briefly described below.

1. AB 1811 – Alternative Fuel Incentive Program

Assembly Bill 1811 provided $25 million in funding to ARB to incentivize biofuels and high efficiency, low emitting vehicle technology and thereby reduce air pollution and greenhouse gas emissions.[18] These funds were awarded by June 30, 2007, consistent with proposed expenditure categories developed jointly by ARB and the Energy Commission. In general, the original funding and categories are presented below:

- $5.4 million for infrastructure for dispensing E85 and potentially other alternative fuels;
- $6 million for the startup of small biofuels production facilities;
- $5 million for hybrid electric vehicle demonstration projects;
- $2 million for transit bus projects;
- $1.8 million for incentives for partial-zero electric vehicles (PZEV) and zero electric vehicles (ZEV);
- $3.2 million for alternative fuel vehicle research; and
- $1.6 million to fund consumer education and outreach.

This program is currently in progress and is expected to expend the funds by the deadline of June 30, 2009.[19]

---

[18] SEC. 14. Item 3900-001-0044 of Section 2.00 of the Budget Act of 2006
[19] Additional information on the projects funded under the AB 1811 program can be found at the following website: http://www.arb.ca.gov/fuels/altfuels/incentives/incentives.htm.

2. AB 118 – California Alternative and Renewable Fuel, Vehicle Technology, Clean Air, and Carbon Reduction Act of 2007

Assembly Bill (AB) 118 (Núñez, Chapter 750, Statutes of 2007) provides grant funding for the alternative fueling infrastructure, fuels, and vehicles needed to meet the requirements of AB 32. The AB 118 funding will help ensure the successful reduction of global warming emissions from California's transportation sector. Three different State agencies have responsibilities from AB 118 implementation.

a. AB 118 – California Energy Commission

Assembly Bill 118 authorizes the Energy Commission to spend up to $120 million per year for over seven years to "develop and deploy innovative technologies that transform California's fuel and vehicle types to help attain the state's climate change policies." The statute, amended by AB 109 (Núñez, 2008), directs the CEC to create an advisory committee to help develop and adopt an Investment Plan for the program. The Investment Plan is intended to determine program priorities and opportunities, and describe how funding will complement existing public and private investments, including existing state and federal programs. The ARB is represented on the advisory committee.

The Energy Commission staff released a draft Investment Plan (Plan) in December 2008 that was presented at an advisory committee meeting on January 8, 2009. The draft Plan includes recommendations for distributing $176 million to six funding categories during the first two years of the program. The draft recommended funding is as follows:

- $62 million for low carbon fuels (e.g., natural gas, propane, biodiesel and renewable diesel);
- $22 million for ultra-low carbon fuels (e.g., biomethane and biogas);
- $41 million for super-ultra-low carbon fuels (e.g. electric drive and hydrogen);
- $22 million for efficiency improvements (vehicle and engine efficiency improvements);
- $19 million for non-GHG reduction categories (e.g., workforce training, sustainability, public education and outreach); and
- $10 million for manufacturing and production.

The Energy Commission staff held four public workshops on the Plan and AB 118 Program in February 2009. The CEC adopted a regulation to administer the Alternative and Renewable Fuel and Vehicle Technology Program on February 25, 2009. A revised Plan is scheduled to be released and proposed to the Energy Commission for adoption in March 2009.

b. AB 118 –Air Resources Board

Under AB 118 provisions, ARB was allocated $50 million annually beginning in fiscal year (FY) 2009-10 for the Air Quality Improvement Program (AQIP). AB 118 allows for the AQIP to fund a variety of clean advanced technology vehicle and equipment projects to reduce criteria pollutant emissions. ARB staff is developing a proposed AQIP FY 2009-10 Funding Plan. The Board is scheduled to consider the Funding Plan in April 2009. At AQIP public workshops, staff has discussed a draft proposal that directs about half of the FY 2009-10 AQIP funds to a new hybrid truck and bus voucher program, with additional funds targeting electric light-duty vehicles, farm equipment, and lawn and garden equipment, as well as advanced technology demonstration projects. Staff expects to solicit FY 2009-10 projects in mid-2009 (once AQIP funds are appropriated as part of the FY 2009-10 California budget), and begin funding projects in late 2009.

The Board will also consider adoption of ARB staff's Proposed AQIP Guidelines -- which define the program's structure and administrative requirements -- in April 2009. The program Guidelines are intended to apply to multiple funding years, while the AQIP Funding Plan shall be updated and approved by the Board annually.

c. AB 118 – Bureau of Automotive Repair

AB 118 provides the Bureau of Automotive Repair about $30 million annually through 2015 for an Enhanced Fleet Modernization Program, which is a voluntary vehicle retirement program for high-polluting cars and light- and medium-duty trucks. The program will be available statewide, with an initial outreach effort in the South Coast and San Joaquin Valley.

D. Federal Renewable Fuels Standard

At the federal level, Congress adopted a renewable fuels standard (RFS) in 2005 and strengthened it (RFS2) in December 2007 as part of the Energy Independence and Security Act of 2007 (EISA). The RFS2 contains, among other provisions, increasing volumes of biofuels every year, up to a required volume of 36 billion gallons by 2022.(8) Of the 36 billion gallons, 16 billion gallons must be advanced biofuels from cellulosic sources. Successful implementation of the RFS2 would result in significant quantities of low carbon intensity biofuels that could be used toward compliance with California's LCFS. In addition, successful implementation would also signal that the necessary technological breakthroughs to produce second and third generation biofuels have occurred.

1. Renewable Fuel Volume Requirements

The RFS2 requires fuel producers to use a progressively increasing amount of biofuel, culminating in at least 36 billion gallons of biofuel by 2022. The U.S. EPA must establish regulations to ensure that transportation fuel sold in or imported into the

United States contains at least the applicable quantity of renewable fuels. Responsible parties under the U.S. EPA regulations relating to biofuels include large refiners, blenders, and importers of gasoline, and small refiners beginning in 2010.

The RFS2 volume requirements are given in Table II-3. The total volume of renewable fuel required in the U.S. in 2009 is 9.0 billion gallons, increasing to 36 billion gallons in 2022. RFS2 differentiates between "conventional biofuel" (corn-based ethanol) and "advanced biofuel." Advanced biofuel is renewable fuel, other than corn-based ethanol, with lifecycle greenhouse gas emissions that are at least 50 percent less than greenhouse gas emissions produced by gasoline or diesel. Beginning in 2009, a progressively increasing portion of renewable fuels must be advanced biofuels, such as cellulosic ethanol.

Table II-3
Federal Renewable Fuels Standard 2 Volume Requirements

Year	Advanced Biofuel			Total Renewable Fuel (billion gal)
	Cellulosic Biofuel (billion gal)	Biomass-Based Biodiesel * (billion gal)	Total (billion gal)	
2008	---	---	---	9.0
2009	---	0.5	0.6	11.1
2010	0.1	0.65	0.95	12.95
2011	0.25	0.8	1.35	13.95
2012	0.5	1.0	2.0	15.2
2013	1.0	*	2.75	16.55
2014	1.75	*	3.75	18.15
2015	3.0	*	5.5	20.5
2016	4.25	*	7.25	22.25
2017	5.5	*	9.0	24.0
2018	7.0	*	11.0	26.0
2019	8.5	*	13.0	28.0
2020	10.5	*	15.0	30.0
2021	13.5	*	18.0	33.0
2022	16.0	*	21.0	36.0

* Per RFS2 requirement, the U.S. Administrator shall determine the applicable biomass-based biodiesel volume and shall not be less than the volume listed from 2012.

2. Renewable Fuels GHG Requirements

The RFS2 does not specifically require GHG reductions for the various categories of renewable fuels and is not a carbon intensity standard like the LCFS. However, there are specific requirements for the different classifications of renewable fuels. In general, these specifications are set relative to the baseline lifecycle GHG emissions for gasoline and diesel fuel sold or distributed in 2005. The lifecycle GHG emissions are specifically defined as:

"The term '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 Administrator, 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."[20]

There are four general classifications of renewable fuels defined in RFS2 as summarized below:

- Conventional Biofuels: Renewable fuel that is ethanol derived from corn starch. Any new facility that commences construction after the date of enactment of the RFS2 must achieve at least a 20 percent reduction compared to the baseline emissions. Practically, about 13 billion gallons for ethanol derived from corn starch is excluded from the 20 percent requirement.
- Advanced Biofuels: As discussed above, an advanced biofuel is any renewable fuel that has lifecycle GHG emissions at least 50 percent less than baseline emissions. An advanced biofuel excludes ethanol derived from corn starch.
- Cellulosic Biofuels: Cellulosic biofuels are a specific subset of advanced biofuels. These fuels must achieve at least a 60 percent reduction in GHG emissions compared to the baseline emissions.
- Biomass-Based Diesel: Biomass-based diesel fuels are also a subset of advanced biofuels. These fuels are specifically defined as biodiesel fuels and must have GHG emissions that are at least 50 percent less than the baseline emissions. A renewable diesel fuel derived from co-processing biomass with a petroleum feedstock can be an advanced biofuel, but is not a biomass-based diesel fuel.

A comparison of the GHG emissions benefits of RFS2 compared to the LCFS is given in the Environmental Chapter and Appendix F.

3. Renewable Biomass Definition

The RFS2 defines renewable fuel as fuel that is produced from renewable biomass. Renewable biomass is then defined as each of the following:

- Planted crops and crop residue harvested from agricultural land cleared or cultivated at any time prior to the enactment of this sentence that is either actively managed or fallow, and nonforested;

[20] Title II-Energy Security Through Increased Production of Biofuels; Subtitle A-Renewable Fuel Standard; Section 201-Definitions;

- Planted trees and tree residue from actively managed tree plantations on non-federal land cleared at any time prior to enactment of this sentence, including land belonging to an Indian tribe or an Indian individual, that is held in trust by the United States or subject to a restriction against alienation imposed by the United States;
- Animal waste material and animal byproducts;
- Slash and pre-commercial thinnings from non-federal forestlands, including forestlands belonging to an Indian tribe or an Indian individual, that are held in trust by the United States or subject to a restriction against alienation imposed by the United States, but not forests or forestlands that are ecological communities with a global or State ranking of critically imperiled, imperiled, or rare pursuant to a State Natural Heritage Program, old growth forest, or late successional forest;
- Biomass obtained from the immediate vicinity of buildings, camps, or public infrastructure facilities (including roads), at risk from wildfire;
- Algae; and
- Separated yard waste or food waste, including recycled cooking and trap grease; and street tree and urban park trimmings.

One aspect of the definition of renewable biomass is that there are significant federal incentive funds for producing advanced biofuels. To qualify for these incentives, the renewable fuels must be produced from renewable biomass. Additional discussion of the relationship between the federal definition of renewable biomass and the LCFS is presented in Chapter 6.

4. U.S. EPA Rulemakings Implementing the RFS2

U.S. EPA is responsible for implementing the volume requirements in the RFS2. Section 211(o) of the Clean Air Act (CAA or the Act), as amended, requires the U.S. EPA Administrator to annually determine a renewable fuel standard which is applicable to refiners, importers and certain blenders of gasoline, and publish the standard in the Federal Register. On the basis of this standard, each obligated party determines the volume of renewable fuel that it must ensure is consumed as motor vehicle fuel. This standard is calculated as a percentage, by dividing the amount of renewable fuel that the Act requires to be blended into gasoline for a given year by the amount of gasoline expected to be used during that year, including certain adjustments specified by the Act.

U.S. EPA published a renewable fuel standard of 7.76 percent for 2008, which was intended to lead to the use of 9 billion gallons of renewable fuel in 2008.(9) Similarly, U.S. EPA published a renewable fuels standard of 10.21 percent for 2009, which was intended to lead to the use of 11.1 billion gallons of renewable fuel in 2009.(10) Note

that the 11.1 billion gallons of renewable fuel required in 2009 is projected to include approximately 0.5 billion gallons of biodiesel and renewable diesel.
The U.S. EPA is scheduled to release another proposed rulemaking in the next few months. Among other provisions, the proposed rulemaking will present the preliminary results of its determinations for the full fuel life cycle analysis and the fuel volume requirements as required by EISA.

E. Other LCFS Initiatives

1. Northeast and Mid-Atlantic States

Eleven Northeast and Mid-Atlantic States have committed to developing a regional Low Carbon Fuel Standard in order to reduce greenhouse gas emissions from fuels for vehicles and other uses.[21] These States will work together to create a common fuel standard that will reduce greenhouse gas emissions on a technology-neutral basis. The standard will be a market-based, technologically neutral policy to address the carbon content of fuels by requiring reductions in the average lifecycle greenhouse gas emissions per unit of useful energy.

The standard would be applicable to transportation fuels. In addition, the standard would apply to fuel used for heating buildings, industrial processes, and electricity generation. Fuels that may have potential to reduce the carbon intensity of transportation include electricity and advanced biofuels that have lower lifecycle carbon emissions and are less likely to cause indirect effects from crop diversion and land use changes than those on the market today. A Memorandum of Understanding concerning the development of the regional low carbon fuel standard program is to be forwarded to the Governors of each State by December 31, 2009, or as soon thereafter as is possible.

ARB staff has been coordinating with representatives of these States and will continue to do as the ultimate success of any LCFS is dependent adoption across jurisdictions.

3. Canadian Provinces

On May 31, 2007 British Columbia and Ontario have signed memoranda of understanding with California to match California's Low Carbon Fuel Standard (LCFS), requiring that the average carbon intensity of transportation fuels sold in the province be reduced by at least 10 percent by 2020.(11)

4. European Fuel Quality Directive

As a part of its plan to reduce overall GHG emissions, the European Commission amended the European Fuel Quality Directive 98/70/EC on December 17, 2008 to include the de-carbonization of transport fuel.(12, 13) Fuel suppliers will be required to

[21] The States are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

report on the lifecycle GHG emissions of the fuel (petrol, diesel, and gas-oil) they supply and reduce these emissions from 2011 onward. Suppliers will be required to gradually reduce GHG emissions per unit of energy by up to 10 percent in 2020. This is to be accomplished through the use of biofuels, alternative fuel, and reductions in flaring and venting.

The major provisions of the amendments are presented below.

- <u>Applicability</u>: Applies to suppliers of fuel for road vehicles, non-road machinery (including inland waterway vessels when not at sea), agricultural and forestry tractors and recreational craft when not at sea.

- <u>Standards</u>:

    - Baseline year is 2010
    - 2 percent reduction by December 31, 2014
    - 4 percent reduction by December 31, 2017
    - 6 percent reduction by December 31, 2010

    - Additional 2 percent reduction requirements by 2020 for either one or both:
        - The supply of energy for transport supplied for use in any type of road vehicle, non-road mobile machinery (including inland waterway vessels), agricultural or forestry tractor or recreational craft; or
        - The use of any technology (including carbon capture and storage) capable of reducing life cycle greenhouse emissions per unit of energy from fuel or energy supplied.

- <u>Sustainability Criteria</u>:

    - Minimum GHG reductions threshold for biofuels (initially 35 %, will eventually increase to 60 % GHG reduction)
    - Biofuels shall not be from made from raw material obtained from land with biodiversity value;
    - Biofuels shall not be from made from raw material obtained from land with high carbon stock (wetlands, continuously forested areas, peat lands); and
    - Biofuels shall not be from made from raw material obtained from land that was peat land in January 2008 unless it is proven that the cultivation and harvesting of this raw material does not involve drainage of previously un-drained soil.

- <u>Verification</u>:

    - Member States shall require economic operators to show that sustainability criteria above have been fulfilled; Economic operators must use a mass balance system to ensure that sustainability criteria apply to all raw materials used in biofuels production;

- Member States shall require economic operators to show appropriate and relevant information on measures taken for soil, water and air protection, the restoration of degraded land, and the avoidance of excessive water consumption in areas where water is scarce;
- Member States shall take measures to ensure that economic operators submit reliable information and to make available to the Member State upon request the data that were used to develop the information; and
- Member States shall require economic operators to arrange for an adequate standard of independent auditing of the information they submit. The auditing shall verify that the systems used by the economic operators are accurate, reliable, and fraud-resistant.

- <u>Lifecycle GHG Emissions from Biofuels</u>:

    - GHG calculation by JCR/ EUCAR/CONCAWE
    - Direct land use included;
    - A study reviewing the impact of indirect land use change is required to be submitted to the European Parliament by December 31, 2010 per the amended directive
    - Look up tables provided for:
        - Default % reduction for each biofuel based of biomass type; and
        - Carbon intensity values for each step in the production of biofuels.

III. Technology Assessment

This chapter contains a brief description of some of the fuels that might be used to comply with the LCFS. Also discussed for each fuel are conversion technologies and production pathways currently available (commercially) or under development. The diversity of promising low-carbon fuel options along with the substantial research and development efforts to bring advanced technologies to the market leads us to conclude that compliance with the LCFS is feasible. The mandate of the federal Energy Independence and Security Act of 2007 (EISA) to use increasing amounts of advanced and cellulosic biofuel(8) beginning in 2009/2010 and continuing on through 2022 will further stimulate improvements to the current conversion technology of advanced biofuels. A more detailed version of this chapter is included as Appendix B.

A. Overview of Current California Transportation Fuels

1. Gasoline

Currently, most gasoline in California contains six percent ethanol by volume. Some blends of eight percent ethanol by volume are available for sale in the State. California consumed about 15.8 billion gallons of gasoline(14)[22] in 2008. California's gasoline consumption represents about 11 percent of the total gasoline consumption in the United States.(15) According to EMFAC2007, there are approximately 25 million gasoline-powered vehicles in California. There are 15 refineries in California making gasoline and diesel fuel.(16) Recently, Kinder Morgan, a common carrier pipeline and terminal operator responsible for distribution of 60 percent of California's motor vehicle fuels, announced that in 2010 gasoline they distribute would have 10 percent ethanol.

2. Diesel

In California, approximately 4.2 billion gallons of diesel fuel(17) were consumed in 2008, which represents about eight percent of the total diesel fuel consumption in the United States. California diesel fuel must meet a 15 parts-per-million-by-weight sulfur standard and specifications limiting the aromatic hydrocarbon content to 10 percent for large refiners and 20 percent for small refiners. There are approximately 875,000 diesel fuel vehicles in California(17). A majority of those diesel-fuel vehicles are heavy-duty vehicles.

B. Current Technologies

This section presents the staff's assessment of fuels and conversion technologies that are currently available for commercial use.

1. Ethanol from Grains and Sugars

[22] The remaining months of 2008 were projected.

Ethanol is an alcohol made by fermenting and distilling simple sugars. Therefore, any biological feedstock that either contains sugar or can be broken down into simple sugars is a potential source for ethanol production. The three main types of biomass feedstock for ethanol production are sugar syrup from sugar crops, starch from grains, and biomass containing cellulose. However, at present, ethanol is produced commercially in large quantities only from enzymatic fermentation of starch from grains and fermentation of sugars from sugar crops (sugarcane, sugar beets, sweet sorghum).

The easiest way to produce ethanol is to begin with sugar-producing plants. For example, sugarcane, sugar beets, and sweet sorghum stalks contain high levels of sugar. The sugar syrup obtained when the feedstock is pressed can be fermented with minimal processing. In contrast, grains contain starch, a polymer of glucose, which must be broken apart before the sugar can be fermented. Therefore, ethanol production from starch-based feedstocks requires more effort than production from sugar-based feedstocks. The third type of biomass feedstock contains cellulose, such as trees, grasses, wood wastes, etc. The cellulose in these feedstocks is part of a lignocellulosic composite in the cell walls that resists degradation. Hence, more energy is required break down this feedstock to its component sugars than with grains or sugar crops. However, the energy requirements to grow cellulosic material are far less than for sugar or starch, which is a significant advantage.(3) Lignocellulosic biomass to ethanol conversion technologies are discussed in the Midterm Technologies section of this chapter. This section focuses on ethanol production from grains and sugar crops.

a. Ethanol from Grains

Currently, corn is the primary feedstock for ethanol production in the United States. Studies indicate that approximately 98 percent of current ethanol production in the United States uses corn, with about 80 percent of the ethanol produced from a dry-mill process.(18) New plants are projected to be dry-mill only, with the exception of a new 100 MGY wet-mill plant for Iowa and a plant expansion project in Tennessee.(19) In California, the existing corn ethanol commercial plants have a production capacity of approximately 150 million gallons per year. Additional corn-to-ethanol plants are under construction that will add to this capacity. Newer plants in operation or under construction in California are energy efficient, maximize co-product value, and produce lower-carbon-intensity ethanol.

(1) Dry Mill

In the dry mill process the grain feedstock is milled into a flour or fine meal to expose the starch. Starch is a polymer of glucose and must be broken down before fermentation. The flour is mixed with water and then cooked at high temperatures with enzymes to convert the starch to sugar and reduce bacterial contamination. After the starch has been hydrolyzed to its component sugars (glucose), the glucose is fermented using yeast under anaerobic conditions. The hydrolysis and fermentation process usually takes 40-50 hours.(18) After fermentation, the ethanol is concentrated to 95 percent using conventional distillation and then dehydrated (e.g. by using molecular sieves, azeotropic distillation, or extractive distillation). The ethanol is denatured, usually by the addition of gasoline, to prevent consumption as an alcoholic beverage.

The whole stillage co-product contains any unfermented starch and the fiber, oil, and protein components of the original grain. The whole stillage is also known as distillers' grain and may be partially dried and mixed with solids to produce wet distillers' grains with solubles (65 percent moisture) for direct use as an animal feed or further dried to 10 -12 percent moisture to produce dry distillers' grain with solubles. The drying process is energy intensive, requiring up to 33 percent of the total energy needs.(18) Wet distillers' grains must be used within hours to days, whereas dry distillers' grain has a much longer shelf life.

(2) Wet Mill

Wet-mill ethanol production differs from dry-mill production in the initial processing steps. In the wet mill process, the grain is steeped in a mixture of water and dilute sulfurous acid for 24 to 48 hours. After steeping, the germ is separated and undergoes further processing to produce an oil product. The gluten is separated from the starch and may be used as a gluten meal for animal feed. The separated starch is then hydrolyzed, fermented, and distilled to produce ethanol as described above for the dry-mill process. Corn is the only grain used in wet mill facilities. The wet-mill process generates valuable co-products, although actual ethanol yield is a little lower than in the dry-mill process.

b. Ethanol from Sugar Crops

The conversion of sugars to ethanol is simpler than the conversion of starch to ethanol as the sugar syrup from pressed sugarcane or sweet sorghum stalks (or obtained from sugar beets) may be readily fermented by yeast with little pre-processing. Under anaerobic conditions, yeast metabolizes sugar to produce ethanol. Fermentation is followed by distillation and purification of the ethanol.

The bagasse (leftover biomass) from sugarcane or sweet sorghum may be used as animal feed, as a potential feedstock for cellulosic ethanol, or burned for electricity. Pulp from sugar beets can be used for animal feed. Waste sugars (such as molasses) or surplus sugar from existing sugar-refining plants are other possible feedstocks for ethanol production.

Sugar-to-ethanol conversion technology is fully commercial (mostly in Brazil). Sugarcane ethanol production is efficient and results in a lower-carbon-intensity ethanol. However, indirect land use effects impact the carbon intensity.

Ethanol produced from sugar crops grown in the United States is also an option, though availability is limited. Ethanol is generally produced from sugars where there is a large supply of feedstock, such as sugarcane in Brazil and sugar beets in parts of Europe. Feedstocks in North America are limited but could be increased. California and other states produce sugar crops for the sugar industry. United States Department of Agriculture (USDA) statistics show that the United States produced a total of 34 million tons of sugar beets and 30 million tons of sugarcane.(18) In California, both sugarcane and sugar beets are farmed in the Imperial Valley. Sugar beets are also cultivated in parts of the Central Valley. Sweet sorghum grows well in California but has not been widely cultivated.

Staff is aware of one sugarcane-to-ethanol facility planned for California. The project is in the permitting phase. The facility will be powered by combusting bagasse and will be located in Brawley near the source of sugarcane cultivation. Production capacity is expected to be 55 million gallons per year.

c. Commercialization Status – Ethanol

In 2007, approximately 13 billion tons of ethanol were produced worldwide. Ethanol production in the United States, nearly all from grains, accounted for about half of the total. Grain-to-ethanol conversion technology is fully commercial. As of February 2009, the Renewable Fuels Association listed approximately 162 operating facilities in the United States that produced ethanol from grain (nearly all from corn), with a total annual production capacity of approximately 10.4 billion gallons of ethanol. Refer to Appendix B for a listing based on the Renewable Fuels Association's list of fuel ethanol biorefineries in the United States, including location, feedstocks, and production capacity.(20) In California, there are five ethanol plants with a production capacity of approximately 150 million gallons.

Ethanol production from sugar crops is also fully commercial. Ethanol production from sugarcane (almost all in Brazil) accounted for roughly 40 percent of the world's fuel ethanol in 2007. Sugar beets are used for ethanol production in parts of Europe. Refer to Table III-1 below for ethanol production in the top five producing nations in 2007.(21)

Table III-1
Ethanol Production in Top Five Producers and
World Ethanol Production Total in 2007

Country	*Millions of Gallons*	*Percent of Total*
United States	*6498.6*	*49.6*
Brazil	*5019.2*	*38.3*
European Union	*570.3*	*4.4*
China	*486.0*	*3.7*
Canada	*211.3*	*1.6*
World Total	*13,101.7*	

In addition to grain and sugar ethanol plants, there are six facilities operating in the United States with a total production of approximately 20 million gallons per year of ethanol from food and beverage wastes. Although the technology is fully developed, there is limited opportunity for growth in this category. Refer to Appendix B for information regarding the location, feedstocks, and operating capacity for these facilities.

2. Biodiesel and Renewable Diesel

a. Biodiesel

Biodiesel is a fuel composed of a mixture of fatty acid alkyl esters that can be made from almost any plant oil or animal fat. “Bio” refers to the biological source of the fuel in contrast to traditional petroleum-based diesel fuel. Biodiesel is an alternative fuel that can be blended with petroleum-based diesel or used in straight unblended form as B100. Biodiesel fuel blends are designated as “BX” where “X” is the percent biodiesel by volume in the fuel. Biodiesel that meets ASTM D975-08ael, ASTM D7461-08, and ASTM D6751-08 is a legally registered fuel and fuel additive with the U.S. Environmental Protection Agency.

The choice of plant feedstocks used to make biodiesel is dependent upon the vegetable oils that are economically available. In the U.S. there are many potential plant-oil feedstocks that can be used, including soybean, peanut, canola, cottonseed and corn oil.(19) Most of the world’s production of biodiesel comes from plant oils such as soybean, rapeseed (canola), and palm oil. About 90 percent of U.S. biodiesel is made from soybean feedstocks.(22) The process used to convert virgin oils into biodiesel involves the use of a catalyst and alcohol and is called transesterification.

Biodiesel can also be made from animal fats, such as used restaurant grease (yellow grease) and tallow. These feedstocks are wastes so there is no CO_2 associated with land use, as there is with crop based feedstocks. Biodiesel from wastes is referred to as advanced biodiesel in order to differentiate it from conventional biodiesel because of its lower carbon intensity. These waste animal fats can be converted into biodiesel through transesterification.

Raw vegetable and animal oils contain triglycerides. Though these oils can be directly used in diesel engines and give short-term performance, this is highly discouraged, as their use can cause severe engine problems. This is primarily due to the raw oils forming engine deposits, with coking and plugging in engine injector nozzles, piston rings, and lubricating oil. This happens due to polymerization of the triglycerides in the raw oils as the fuel is combusted. Therefore, it is necessary to convert the raw oils into a form of esters or biodiesel to prevent these issues.(19)

The conventional biodiesel manufacturing process converts oils and fats into chemicals called long-chain mono-alkyl-esters. These chemicals are also referred to as fatty acid methyl esters (FAME), and the conversion process is referred to as transesterification.

Before transesterification is conducted, the raw oils and fats are filtered and pretreated to remove water and contaminants. Water in the feedstock leads to the formation of soaps, which is an undesirable by-product, reduces the yield of biodiesel, and makes the separation of glycerin in the products more difficult.

Transesterification involves reacting triglyceride oils with alcohol (usually methanol) in the presence of a catalyst in a simple closed-reactor system at low temperature and pressure. In the transesterification reaction vessel, the mixture of alcohol and oils is allowed to settle for one to eight hours.(18) The products of the transesterification reaction are methyl esters (crude biodiesel) and glycerin as a co-product. After transesterification, a majority of the alcohol is removed from the glycerin and recycled back into the system to continue the process. The biodiesel from the process is purified and washed to remove residual catalyst and soaps. The glycerin from transesterification can be purified and sold to the pharmaceutical or cosmetic industries to be processed into lotions and creams.

According to the National Biodiesel Board as of September 2008 there were 176 operational commercial biodiesel production plants in the U.S. with a total production capacity of 2.61 billion gallons. There are about seven major plants in California with annual production capacities varying between 350,000 gallons to ten million gallons. The total capacity in California is nearly 35 million gallons per year. See Appendix B for a biodiesel commercialization status summary from the National Biodiesel Board giving plant location, capacity, and feedstock of plants in the U.S.

b. Renewable Diesel

Hydrogenation-derived renewable diesel (HDRD) is produced by refining fats or vegetable oils. This process is also known as the Fatty Acids to Hydrocarbon (FAHC – Hydrotreatment) process. Vegetable oils and animal fats can be converted into diesel, propane, and other light hydrocarbons through hydrotreatment with hydrogen. Biomass based diesel produced from the FAHC process is referred to as renewable or "green" diesel to differentiate it from biodiesel produced by transesterification. Renewable diesel has a chemical structure that is identical to petroleum based diesel since it is free of ester compounds.

The product distribution of the FAHC process results in (by weight) 83 to 86 percent diesel, two to five percent light hydrocarbons, carbon dioxide gas, and water. The oxygen within the ester compounds of the oils is removed through the release of the carbon dioxide and water.

Renewable diesel has several advantages to FAME and petroleum biodiesel. Renewable diesel has a superior emission profile. Using renewable diesel results in reduced particulate, NOx, hydrocarbons, and CO emissions. Unlike FAME biodiesel, the production of renewable diesel through the FAHC process does not produce a glycerin co-product. Renewable diesel is produced using existing hydrotreatment process equipment in a petroleum refinery, resulting in an economic advantage by reducing the costs of production.

Renewable diesel has a lower sulfur content than petroleum diesel resulting in lower SOx emissions. Renewable diesel has a lower cloud point than conventional biodiesel; therefore, it has better low-temperature operability and can be used in colder climates without gelling or clogging of fuel filters.

Waste animal fats can also be hydrogenated to produce diesel-range hydrocarbons. Renewable diesel produced from wastes has a lower carbon intensity and is also referred to as “Advanced” renewable diesel.

ConocoPhilips completed a commercial demonstration plant in Cork, Ireland, that produces 42,000 gallons per day of renewable diesel using vegetable oil and crude oil feedstocks. ConocoPhilips also partnered with Tyson to build a facility that can process animal fats in the U.S. The facility opened in late 2007 with a capacity of 500,000 gallons per day of renewable diesel.(18)

Neste has developed a plant to process vegetable and animal fats into renewable diesel by the hydrotreatment process. The facility demonstrated at the Porvoo oil refinery in Finland has a capacity of 60 million gallons per year. The company is planning to build a second plant of the same size to meet growing demand. The company also has plans to build plants in Austria and Singapore.

The Petrobras “H-BIO” process uses co-processing of vegetable oils to make renewable diesel. Petrobras plans to have H-BIO operations in at least three refineries by the end of 2007 with a total capacity to handle more than 250,000 tons of vegetable oil annually. Two more refineries were planned for 2008.

Other companies that have plans to produce renewable diesel through hydrogenation include Nippon Oil in Japan, BP in Australia, Syntroleum and Tyson Foods in the U.S., and UOP-Eni. The Nippon Oil plant expects to be operating commercially in three years. The BP plant is planned to have a demonstrated capacity of 80,000 gallons per day. Syntroleum and Tyson Foods are scheduled to start operation in 2010 with a capacity of 5,000 barrels a day. UOP-Eni is an American and Italian project supported by the U.S. Department of Energy that is scheduled to come online in 2009. Refer to Appendix B for a summary of the main HDRD projects in the world.

3. Biogas

Biogas typically refers to a gas produced by the biological breakdown of biodegradable organic matter in the absence of oxygen. This process is also referred to as anaerobic digestion. The resulting biogas consists of methane, carbon dioxide, and other trace amount of gases and can be used to generate heat, electricity, and alternative fuels. Depending on where it is produced, biogas can be categorized as “landfill gas” or “digester gas.” Landfill gas is produced by decomposition of organic waste in a municipal solid waste landfill. Digester gas refers to applications using livestock manure, sewage, food waste, etc. Biogas is also referred to as biomethane. It has properties similar to natural gas and can potentially be used for similar applications. For example, biomethane might be compressed and used as a transportation fuel in compressed natural gas vehicles.(3) The vehicle fuel potential in landfill and sewage digester biomethane is equivalent to between 300 to 400 million gallons of gasoline, whether as compressed or liquefied gas (i.e; CNG or LNG) or converted to hydrogen.(3)

a. Landfill Gas (LFG)

The California Integrated Waste Management Board (CIWMB) has identified approximately 366 landfills with potential to generate landfill gas, of which 145 are active permitted facilities receiving waste. Of the active landfills, approximately 66 percent are owned by public entities.(23) The total potential biomethane resource from landfills in California is estimated at 80 billion cubic feet per year(24). Active landfills must control landfill gas to control migration and reduce explosion risks to adjacent structures. LFG collection systems are well established and use a network of wells, headers, and blowers to collect the gas and route it to a treatment plant or a flare. Raw landfill gas is about 50 percent methane, 45 percent carbon dioxide and a small percentage of other compounds, such as nitrogen and hydrogen sulfide. The average heating value is about 450 Btu/scf.

LFG is currently used for power generation, mostly with reciprocating engines and microturbines. The gas is also used with fuel cells, as boiler fuel, and as vehicle fuel, although much is still flared without energy recovery. The potential use of LFG as a transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG) is discussed below.

(1) Vehicle Fuel from Landfill Gas

The main steps involved in processing landfill gas into CNG are water removal, pretreatment to remove trace organics, membrane technology to separate CO_2, and final compression to about 3600 psi.

Production of LNG from landfill gas is more challenging and requires additional steps in the form of purification and cryogenic systems.

(2) Commercialization Status - LFG

The technology for producing CNG from LFG is well established. The Los Angeles County Sanitation District has successfully converted LFG to CNG since 1994 at its Clean Fuels facility. This facility has a design capacity equivalent to 1000 gallons of gasoline per day. The total capital cost for this project was approximately $1 million.(25) In Sonoma County, a landfill-gas-to-CNG project will result in a system to fuel six buses.

The ECOGAS Corporation has operated an 8,500 gallon-per-day (GPD) LNG plant in Rosenberg, Texas, since 1995.(25) Currently, California does not have any commercial plants in operation for producing LNG. However, ARB and CIWMB have approved grants in 2007 for two commercial-scale demonstration projects. These projects include a 13,000 GPD LNG plant at the Altamont Landfill (by Gas Technology Institute) to be used for the waste-hauler fleet and an 18,600 GPD plant at the Bowerman Landfill (by Prometheus Energy Company) to provide fuel for the local bus fleet.(26) These plants are expected to be commissioned by June 2009 and will provide good data on technical feasibility and costs.

b. Digester Gas

Typical feedstocks for anaerobic digestion include manure from confined animal facilities, such as dairies and feedlots, sewage sludge, and wastes from food processing. Anaerobic digestion is a biochemical process in which several types of bacteria work together in a series of steps to digest biomass in the absence of oxygen. First, bacteria break down the carbohydrates, proteins and fats present in biomass feedstock into fatty acids, alcohol, carbon dioxide, hydrogen, ammonia and sulfides. This stage is called "hydrolysis" or "liquefaction." Next, acid-forming bacteria further metabolize the products of hydrolysis into acetic acid, hydrogen and carbon dioxide. Finally, methane forming (methanogenic) bacteria convert these products into biogas.(27)

The biogas generated by digesters contains methane, carbon dioxide, sulfur compounds, PM, and water. Because the methane in the biogas is dilute and contains contaminants, the biogas must be pretreated, conditioned, and compressed before use as a fuel. The energy content of biogas depends on the amount of methane it contains. Methane content may vary from about 55 percent to 80 percent.[2]

(1) Digester Gas Applications

Digester gas can be used in many applications. The level of pretreatment depends upon the application and is designed to remove carbon dioxide, sulfur compounds, particulates, water, and other contaminants. Typical applications are onsite use in reciprocating internal combustion engines, turbines, boilers, or fuel cells to produce energy. Biomethane can also be injected into a natural gas transmission pipeline or used for transportation purposes. Using digester methane generated onsite to power electricity-generating engines could replace electricity generated from fossil-fuel power plants. In addition, biomethane generated from onsite digesters could power vehicles used for transportation common to a particular industry (e.g. biomethane produced from dairy lagoon digesters can power converted diesel milk trucks).

(2) Commercialization Status – Digester Gas

Production of renewable energy, improvement on environmental pollution in air and water, reduction of agricultural wastes, and utilization of byproducts as fertilizers from anaerobic digestion has increased the attractiveness of this application. Anaerobic digestion technology to produce biogas is well developed worldwide. Currently, the European Union has a total generating capacity of 307 megawatts (MW) from this technology. In California, only 0.37 MW of power is generated from five existing digesters, although the total potential for animal waste to energy in dairies is over 105 MW. There are approximately 2,300 dairy farms in California. There are 10 sewage treatment plants in California with digesters that generate about 38 MW of electrical power.(28)

Use of digester gas to power vehicles is not prevalent but can be achieved. Hilarides Dairy was awarded a grant by ARB in 2007 to produce methane from the waste generated by the dairy's 9,100 cows. This project is an attempt to manage environmental issues and create an onsite self-contained system of energy supply. The biogas generated will power the dairy's four converted milk trucks (reducing diesel consumption by 650 gallons per day) and create an additional 250 kW of electricity for on-site use.(29)

4. Natural Gas (CNG, LNG)

The production of natural gas, in both compressed (CNG) and liquefied (LNG) forms, involves mature technologies and is clearly technologically feasible vis-à-vis the LCFS regulation. Britain was the first country to commercialize the use of natural gas. Around 1785, natural gas produced from coal was used to light houses, as well as streetlights.(30) In 1821, William Hart dug the first well in the U.S. (in Fredonia, New York) specifically intended to obtain natural gas.(30) Natural gas liquefaction dates back to the 19th century,(31) and the first commercial liquefaction plant began operation in West Virginia in 1917.(32) Today, the natural gas industry has existed in this country for over 100 years, and it continues to grow.(30)

CNG is typically transported by pipeline. According to the Energy Information Administration (EIA), the U.S. produced nearly 19.1 trillion cubic feet(33) (Tcf) of "dry" natural gas[23] and imported about 3.8 Tcf in 2007(34), primarily from Canada and a small percentage from Mexico.

LNG is typically transported by specialized tanker with insulated walls, and is kept in liquid form by autorefrigeration, a process in which the LNG is kept at its boiling point, so that any heat additions are countered by the energy lost from LNG vapor that is vented out of storage and used to power the vessel.(30) According to the EIA, the U.S. imported about 0.77 Tcf of LNG in 2007.(34) In 2008, the U.S. imported the vast majority of its LNG from Trinidad, Egypt, Nigeria and Algeria, with much smaller amounts from Qatar and Equatorial Guinea.(34)

The actual practice of processing natural gas to pipeline dry-gas-quality levels can be quite complex, but usually involves four main processes to remove the various impurities:

- Oil and Condensate Removal

[23] Dry gas is natural gas that is almost entirely methane, produced from "wet" gas that is stripped of other molecules during processing or that is produced from non-associated gas fields as "dry" gas.

- Water Removal
- Separation of Natural Gas Liquids
- Sulfur and Carbon Dioxide Removal.(30)

In addition to the four processes above, heaters and scrubbers are installed, usually at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the gas does not drop too low. With natural gas that contains even low quantities of water, natural gas hydrates have a tendency to form when temperatures drop. These hydrates are solid or semi-solid compounds, resembling ice crystals. Should these hydrates accumulate, they can impede the passage of natural gas through valves and gathering systems. To reduce the occurrence of hydrates, small natural gas-fired heating units are typically installed along the gathering pipe wherever it is likely that hydrates may form.(30)

For LNG, the gas must be liquified which involves cooling natural gas at its initial production facility to about -260°F at normal pressure.(30) Upon arrival at its destination in the U.S., LNG is generally transferred to specially designed and secured storage tanks and then warmed to its gaseous state – a process called regasification.(35) The regasified natural gas is generally fed into pipelines for distribution to consumers. However, if the regasified natural gas is intended to be transported or otherwise used as LNG (e.g., in LNG vehicles), it would need to undergo a second liquefaction step, which would substantially increase the fuel's carbon intensity value.

5. Electricity

The power system ("the grid") produces and delivers electrical energy to customers. Electricity is produced by power plants of different sizes and types, which can be fueled by a number of energy sources, such as coal, nuclear, natural gas, wind, solar, and hydropower.

Battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) are examples of two technologies that use electricity as a transportation fuel. The status of zero-emission vehicle technologies was examined by an independent expert review panel (Panel) established by ARB in 2006. The Panel organized its efforts around three main ZEV-enabling technologies: energy storage, hydrogen storage, and fuel cells.(36) Refer to Appendix B for the Executive Summary of the Panel's report published in April 2007.

It is the Panel's opinion that PHEVs have the potential to provide significant direct societal benefits and are likely to become available in the near future. The Panel's projection is that PHEVs can achieve mass commercialization (100,000's of vehicles per year) based on global volumes in the 2015+ timeframe.

Full-performance battery electric vehicles capable of high-speed U.S. urban/suburban freeway driving will grow more slowly due to customer acceptance of limited range and long recharge times. ZEVs are not likely to achieve mass commercialization in the foreseeable future. The Panel projects this technology to achieve early commercialization (10,000's of vehicles per year) based on global volumes in the 2015 timeframe.

Concerns have been raised about the potential impact of a growing number of plug-in hybrid or electric vehicles on the supply of available electrical power and the need for additional power plant development. Recent research has shown that there is an ample supply of idle electrical generation and transmission capacity to accommodate a significant increase in electric vehicle use.

A 2007 Department of Energy Study found the nation's supply of fossil-fuel based, off-peak electricity production and transmission capacity could fuel up to 84 percent of the country's existing 220 million vehicles if they were all plug-in hybrids. The study assumed drivers would charge their vehicles overnight when demand for electricity is much lower and did not include hydroelectric, nuclear, renewable, or peaking power plants in its estimates.

The study found that in the Midwest and East, there is sufficient off-peak electrical generation and transmission capacity to provide for all of today's vehicles if they ran solely on batteries. In parts of the West, and specifically the Pacific Northwest, where there is a large amount of hydroelectric generation that's already heavily utilized and cannot be easily expanded, there is a more limited supply of extra electricity-generating capacity. However, the study found 15 to 23 percent of California and Nevada's 26 million light-duty vehicles could be fueled with idle, off-peak electricity generating capacity within the California/Nevada study area.(37)

Research conducted by the Electric Power Research Institute found that more than 40 percent of the nation's electric generating capacity sits idle or operates at reduced loads overnight and could accommodate tens of millions of plug-in hybrids without requiring new plants.(38) The research also concludes utilities could better capitalize their power-generating assets by allowing for more efficient operation and gaining a new market for off-peak power that now sits idle.

The additional 1.8 million electric vehicles by the year 2020 are expected to increase the State's electric system load demand by 4.6 TW-hrs by 2020. Since most of this additional demand would be supplied by off-peak power, electric vehicles would not create an adverse impact on California's supply of available electric power within the 2020 timeframe.

A potential benefit of plug-in or electric vehicles for the "smart" power grid of the future involves the concept of using the stored energy in electric vehicles to supply power to the grid during peak demand periods. This "vehicle-to-grid" (V2G) concept would involve advanced technology that would allow future plugged-in vehicles to transmit their location and storage capacity to the electric power grid. Utilities could potentially draw small amounts of power from the vehicle's battery packs to provide voltage regulation, spinning reserves, and other power balancing functions. While some V2G research has been conducted, deploying this technology will require significant investments to evolve the existing grid and will require large-scale use of plug-in vehicles to provide any potential value to utilities or grid operators.(39)

6. Hydrogen

Hydrogen can be used in vehicles with high efficiency and zero tailpipe emissions. Hydrogen can be produced from a range of primary sources, including fossil fuels (natural gas, coal, oil), renewables (biomass, wind, solar), or nuclear energy. Syngas-based processes like steam methane reforming or coal gasification are well established. Water electrolysis is a commercial technology that is used where low-cost electricity is available. It should be noted that with the use of carbon capture and sequestration, hydrogen from traditional sources can be close or equivalent in carbon intensity to hydrogen from renewable sources.

For storage and transport to users, hydrogen is compressed to high pressure or liquefied at very low temperature. Hydrogen can be produced onsite at refueling stations (via small-scale steam reforming of natural gas or water electrolysis) or in a large central plant and delivered to users in compressed gas or liquid hydrogen trucks or via gas pipelines.

The status of zero-emission vehicle technologies was examined by an independent expert review panel (Panel) established by the ARB in 2006. For the Executive Summary of the Panel's report published in April 2007, refer to Appendix B. It is the Panel's view that storing hydrogen on a vehicle to power it for adequate distance in a safe and cost-effective manner without excessive weight is a serious challenge in the development of fuel cell electric vehicles. In the near term, the most common means of storing hydrogen onboard light vehicles will continue to be compressed hydrogen gas. The Department of Energy has selected hydrogen storage parameters corresponding to a 300 mile range as a 2015 target. Liquid hydrogen storage is being demonstrated as workable but with limitations. The California Hydrogen Highway Network Blueprint Plan calls for a total of 50 hydrogen refueling stations by 2010, and as many as 250 in the longer term.(3)

Automotive fuel cell technology continues to make substantial progress but is not yet proven to be commercially viable. The Panel's 2007 report states that "there are still large technical barriers to be solved but these might well be overcome over the next five to 10 years." The Panel's projection is that the intense effort on fuel cell electric vehicles will result in technically capable vehicles by the 2015 to 2020 timeframe, but successful commercialization is dependent on meeting challenging cost goals and availability of an adequate hydrogen infrastructure. The Panel projects this technology to be in a pre-commercial stage (1000's per year) based on global volumes in the 2010 to 2020 timeframe.

A National Academy of Sciences study also suggests the possibility of introducing hydrogen fuel cell vehicles on a commercial basis in the United States in the 2015-2020 timeframe.(40)

C. Mid-Term Technologies Projected by 2015

This section groups the fuels and conversion technologies expected to be available for commercial use in the 2015 timeframe.

1. Lignocellulosics to Ethanol

Producing ethanol from cellulose has the potential to greatly increase the volume of ethanol that can be produced. Cellulose is the main component of plant cell walls and is the most common organic compound on earth. The quantity and diversity of potential feedstocks is substantial compared to starch and sugar crops. In addition to biomass from dedicated agricultural crops, crop and forest residues and waste biomass may be collected and used for cellulosic feedstock. In addition, cellulosic pathways to bioethanol and other biofuels have the potential to result in lower-carbon-intensity values and improved net-energy ratios than the traditional starch- and sugar-based ethanol production.(3)

Lignocellulosic (cellulosic) feedstocks include dedicated crops, crop and forest residues, or wastes (municipal solid waste, furniture manufacturing wastes, etc.). Lignocellulosic biomass from all the principal feedstocks consists mainly of cellulose (40-60 dry weight percent) and hemicellulose (20-40 dry weight percent). Cellulose and hemicellulose are both sugar-based complex carbohydrates and, after hydrolysis to their component sugars, may be fermented to ethanol. Most of the remaining fraction of cellulosic biomass is lignin (10-28 dry weight percent), but there are also smaller amounts of proteins, lipids, and ash. Lignin cannot be fermented but can be used directly for fuel or thermochemically treated to produce syngas (gasification) or bio-oils (flash pyrolysis). Currently, the combustion of lignin is used to generate electricity and/or as a heat source for boilers in some existing small-scale fermentation pathway plants.

The chemical composition of a particular feedstock (cellulose/hemicellulose/lignin ratio) is an important factor in the ethanol yield for the hydrolysis/fermentation pathway. A lower lignin percentage results in a higher ethanol yield. Woody biomass has about 27 percent lignin, while grasses such as switchgrass have about 18 percent.

An emerging source of cellulosic feedstock is native prairie grasses, such as switchgrass, that may be grown on marginal lands with little water and no fertilizer. This feedstock is particularly attractive for some Midwestern locations. Other potential cellulose-to-ethanol feedstocks include fast-growing woody crops such as poplar and willow trees.

Crop residues, such as corn stover or rice straw may be collected as a co-product of other crops. In other states, facilities have been proposed to utilize corn stover as a feedstock. However, studies have noted that crop residue removal can affect soil erosion or decrease soil organic composition, which can impact life-cycle greenhouse gas reductions. Other potential biomass feedstocks include bagasse from sugarcane or sweet sorghum, orchard prunings, and forest residues. Cellulosic waste feedstock includes municipal solid waste, wood waste from furniture manufacturing, and construction and demolition debris. The cellulosic ethanol plants projected to be built in California will use residues or wastes as feedstocks. Ethanol produced from wastes has no land use component for carbon intensity and qualifies as advanced renewable ethanol.

a. Lignocellulose to Ethanol Conversion Technologies

The traditional pathway to produce lignocellulosic ethanol from biomass is through hydrolysis and fermentation. This process is similar to production of ethanol from grains, except that it is significantly more difficult to hydrolyze lignocellulose than starch. An alternative pathway involves gasification of lignocellulosic biomass to produce syngas. The syngas can be converted to ethanol using a modified Fischer-Tropsch synthesis or by fermentation techniques.

b. Commercialization Status – Lignocellulosic Ethanol

Current studies typically categorize lignocellulose-to-ethanol conversion technology as ready for commercialization in the midterm. However, current technology is available for limited near term (2010) production.[24] Good progress has been made during the last few years toward producing ethanol from cellulosic feedstocks.[25] Several technologies, proven in pilot-scale facilities are moving toward commercialization. Challenges remain in scaling the technologies, reducing production costs, and financing large-scale plants.

There are a number of government and renewable-fuels-industry research and development programs dedicated to overcoming remaining hurdles to large-scale commercial production of renewable fuels from cellulosic biomass. Areas of interest for continued research include developing more efficient pretreatment technologies, developing lower-cost and more effective cellulase enzymes, engineering strains of microorganisms that have higher conversion yields, and integrating multiple process steps into fewer reactors.

The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 (EISA) provide funds for research and development that should facilitate improvements to the current conversion technologies. Both the United States Department of Energy

[24] The Antares Group 2008 paper (pg 26) categorized as near term (2010) dilute acid hydrolysis conversion technology. Small size facilities of 25 to 60 MGY were modeled. With current technology, a 35 percent conversion to ethanol and an overall process efficiency of about 60 percent were projected for the near term (pg 24). Mid term processes (2015 to 2020) were modeled with the assumption of higher conversion efficiencies and yields. With dilute acid pretreatment, a facility size of 60-100 MGY is modeled. Steam explosion pretreatment is modeled for large facilities > 100 MGY (pg 26).

[25] Regulatory Impact Analysis, April 2007, pg 263 states that "good progress continues to be made and we remain optimistic that cellulosic ethanol will become increasingly important in the future," pg 263.

(DOE) and the USDA are funding research to improve cellulosic conversion and to develop higher yielding biomass crops. On February 28, 2007, the DOE announced that it would provide six grants of up to $385 million in cost-share funding for the construction of six biorefinery projects over the next four years. These facilities were expected to produce more than 130 million gallons of cellulosic ethanol per year.(19) Of the original six grant recipients, two have dropped out of the program. The remaining four recipients expect to complete commercial-scale facilities between 2009 and 2012.

In addition to funding research and development, the EISA provides a compelling incentive for cellulosic ethanol production. Beginning in 2010 and continuing through 2022, the EISA mandates that transportation fuels sold or introduced into commerce in the United States must include increasing amounts of cellulosic biofuels (a subset of advanced biofuels) as part of the Renewable Fuel Standard. By 2015, the EISA requires that transportation fuels contain at least 3.0 billion gallons of cellulosic biofuel. In 2020, the mandated volume of cellulosic biofuels increases to 10.5 billion gallons. By 2022, 16.0 billion gallons of transportation fuels must come from cellulosic feedstocks. Corresponding EISA-mandated volumes of advanced biofuels for 2015, 2020, and 2022 are 5.5, 15.0, and 21.0 billion gallons, respectively.

Given the progress in current research and development efforts and the EISA mandate of at least 3.0 billion gallons of cellulosic biofuel (5.5 billion gallons of advanced biofuel) in 2015, staff is optimistic that significant volumes of cellulosic ethanol can be produced by 2015.

2. Lignocellulosics to Renewable Diesel

Biomass feedstocks including lignocellulosic crops, crop residues, and wastes can be converted into diesel-range hydrocarbons. The two main pathways for the conversion of biomass into renewable diesel include the pyrolysis and hydrotreatment process to make bio-oil and the gasification and Fischer-Tropsch (F-T) process to produce F-T diesel. Bio-oil and F-T fuels can be upgraded into gasoline or diesel-range hydrocarbons (renewable gasoline or renewable diesel fuel). In general, the processes using biomass feedstocks to produce renewable diesel are more complex and less commercialized than those used to produce biodiesel from virgin plant oils and animal fats. However, the processing through lignocellulosic pathways, especially for wastes, can result in lower-carbon-intensity fuels.

3. Lignocellulosics to Renewable Gasoline

As with renewable diesel, biomass feedstocks including lignocellulosic crops, crop residues, and wastes, can be converted into gasoline-range hydrocarbons. The two main pathways for the conversion of biomass into renewable gasoline include the pyrolysis and hydrotreatment process to make renewable gasoline and the gasification and Fischer-Tropsch (F-T) process to produce F-T gasoline. As with renewable diesel, the processing through lignocellulosic pathways, especially for wastes, can result in lower-carbon-intensity-fuels.

4. Classic Fischer-Tropsch Fuels

Synthetic liquid fuels are produced from fossil-fuel resources that cannot reasonably be classified as petroleum. The two fuels discussed here are natural gas-based synthetic fuels (also called gas-to-liquids, GTLs, or GTL synfuels) and coal-based synthetic fuels (also called coal-to-liquids, CTLs, or CTL synfuels). The classic Fischer-Tropsch process is a catalyzed chemical reaction in which synthesis gas, a mixture of carbon monoxide and hydrogen, is converted into liquid hydrocarbons of various forms. Many refinements and adjustments have been made to the original process invented in the 1920s.

a. Coal to Liquids

The production of CTL fuels begins with coal as a raw material or feedstock. In indirect coal liquefaction, prepared coal is subjected to heat and pressure in the presence of steam and oxygen to create a synthesis gas. The synthesis gas is treated to remove impurities and is sent to a high-temperature (300-350 degrees Celsius) or a low-temperature (200-240 degrees Celsius) Fischer-Tropsch (F-T) reactor. A low-temperature reactor is used to maximize the production of renewable diesel, while the other is used to maximize renewable gasoline production. The syngas must be cleaned by removing sulfur halides and nitrogen before it enters the reactor because they will poison the F-T catalyst which is usually made of iron or cobalt. Four different types of beds have been used commercially, including multi-tubular fixed bed, circulating fluidized bed, fixed fluidized bed, and fixed slurry bed reactors.

<u>Commercialization Status - CTL</u>

Sasol in South Africa has been producing coal-derived fuels using F-T technology since 1955. The total capacity of the South African CTL operations now stands in excess of 160,000 barrels per day of product. There are a number of CTL projects around the world at various stages of development, the most advanced being in China, the U.S., and Australia.

b. Gas to Liquid (GTL) Fuels

Gas-to-liquid (GTL) fuels are fuels derived by converting natural gas into longer-chain hydrocarbons by the low temperature Fischer-Tropsch process to produce diesel range fuels and co-products for the California market.(41) The GTL process is an umbrella term for a group of technologies that convert natural gas into these products. The processes are based on those first conducted by Sasol's plant mentioned above that uses natural gas as a feedstock for the F-T process.

The GTL conversion process involves reforming the natural gas feedstock, and converting it into a syngas rich in hydrogen and carbon monoxide. The syngas is then run through the F-T reactor. The products from the F-T reactor are then separated into GTL diesel, naphtha, lubricant base oils, and normal paraffin.

Project proponents for GTL have claimed that their GTL products are low in sulfur and aromatics and in many cases have a lower carbon intensity than conventional refinery analogues. The low sulfur and aromatics result in a superior emission profile for GTL diesel.

D. Long-Term Technologies Projected after 2020

This section discusses the fuels and conversion technologies which are expected to be available on a commercial scale after 2020. In addition, a discussion of carbon capture and geologic sequestration is included in this section.

1. Biofuels from Algae

The overall potential of biofuel production from algae is significant. It is generally accepted that approximately half of the global biomass originates in the oceans.(42) Algae use the energy from sunlight to produce simple sugars, then convert these simple sugars into oils or complex carbohydrates, and store these substances in cells. Cultivation of algae can be the route to multiple bioenergy sources and an especially effective way to reduce greenhouse gas emissions. Potential algal-derived fuels include biodiesel, ethanol, Fischer-Tropsch fuels, hydrogen, alkanes, and methane. Typically, oils from microalgae (microscopic) are the feedstock for biodiesel production, whereas polysaccharides from macroalgae (seaweed) are the feedstock for ethanol. However, the biomass fraction of microalgae can also be converted to ethanol and other biofuels.(3) Current research and development efforts in the U.S. have largely focused on microalgae as a source of oils. Several species produce high oil yields that greatly outweigh yields from conventional crops.(3)

There are significant environmental benefits from cultivating algae for biofuel production. Algae fix atmospheric CO_2 normally but may also sequester CO_2 in waste streams from power plants, refineries, or other industrial sources. Algae can thrive in small areas of land that are unsuitable for conventional crops, using high salinity water that is unfit for agricultural or domestic use. Algae also have value in managing nutrients in wastewater treatment. Cultivation of algae may provide multiple benefits concurrently. For example, production of algae in conjunction with wastewater treatment (with CO_2 addition from combustion emissions) has the potential of fixing CO_2, removing soluble nitrogen and phosphorous in the wastewater, and producing O_2, as well as generating biomass for biofuel feedstock.

Biofuel production from algae has been a continuous topic of research since the 1970s. The DOE investigated algae-to-biofuel production in the Aquatic Species Program from the late 1970s to 1996. There are a number of companies conducting research using pilot-scale projects to produce fuels from algae. These projects include using open ponds to grow algae, using bioreactor systems that feed CO_2 combustion emissions to algae, and using algae grown in water systems to produce biofuel.

Although research is progressing, there are still a number of hurdles that must be overcome before commercial production of biofuels from algae is a reality. Algae have particular culture requirements that must be met in order to produce near their theoretical potential. Maintaining requirements for optimal algal growth can be a challenge. For example, light conditions change as the density of cultures increases, which can limit the ability of the algae to convert sunlight into biomass. Solutions to problems so far have been specific rather than general in application. As research progresses, there are opportunities for breakthroughs, but it appears that the technology will not be fully commercialized until sometime after 2020. Harvesting, oil extraction, and cell-wall deconstruction for sugars still present technical and economic hurdles.(3) To date, there are no commercially operating algae-to-biofuel production facilities in California.

2. Butanol

Butanol is a four-carbon alcohol that is typically derived from petroleum refining and is used as an industrial solvent and an intermediate feedstock for the manufacture of other chemicals. This section discusses the feedstocks, pathways, and commercialization status of butanol produced from biomass. Efforts are being made to commercialize biobutanol for use in blends with gasoline to be offered for sale within California. The benefits of biobutanol as an alternative fuel are recognized through its explicit mention in the Renewable Fuel Standard in EISA.

The properties of biobutanol make it amenable to blending with gasoline. It is also compatible with ethanol blending and can improve the blending of ethanol with gasoline.(43) As a renewable fuel, butanol has a number of advantages over ethanol. Butanol has higher energy density than ethanol, can be mixed with gasoline in more flexible proportions than ethanol, and is less corrosive, less volatile, and less water soluble than ethanol. As a result, butanol can be transported through existing fuel pipelines. However, the incomplete combustion of butanol can result in small amounts of butyric acid, which has a strong odor.(3)

a. Feedstocks

Biobutanol can be produced from the same feedstocks as ethanol. Any biological feedstock that contains sugar or that can be broken down into simple sugars is a potential source for biobutanol production via fermentation. The three main types of biomass feedstock for biobutanol production pathway are starch from corn, sugars from sugar crops, and biomass containing cellulose.

The easiest way to produce butanol via fermentation is to begin with sugar-producing plants like sugarcane or sugar beets. The sugar syrup obtained when the feedstock is pressed can be fermented with minimal processing. In contrast, corn contains starch, a polymer of glucose, which must be broken apart before the sugar can be fermented, requiring more energy input. The third type of biomass feedstock contains cellulose, such as trees, grasses, wood wastes, etc. The cellulose in these feedstocks is part of a lignocellulosic composite in the cell walls that resists degradation. Hence, more energy is required break down this feedstock to its component sugars than with corn or sugar crops.

b. Conversion Technology

Several conversion technologies exist to produce butanol from biomass, including biochemical mechanisms (fermentation) and thermochemical mechanisms (gasification followed by a mixed alcohol reactor). However, alcohols derived from biomass (including butanol) are generally produced through fermentation. The traditional fermentation pathway that yields butanol is known as clostridial acetone butanol ethanol (ABE) fermentation. The ABE fermentation process to produce butanol has been known since World War I and was commonly used until the 1950s, when butanol derived from petroleum refining became widely available and more cost effective. During the oil crisis of the 1970s, interest resumed in biobutanol production for a while and then waned by the 1990s. At present, due to environmental and economic concerns, active research is again underway to improve the technology and cost-effectiveness of biobutanol production.

The ABE pathway produces n-butanol, one of four possible butanol isomers. As the name of the fermentation pathway implies, in addition to butanol, acetone and ethanol are co-products. Hydrogen is also a co-product of ABE fermentation. Historically, a few naturally occurring species of the bacterial genus *Clostridium* were used in the ABE fermentation process. However, recent advances in genetic engineering have produced other types of microorganisms capable of making butanol. For example, researchers have demonstrated that genetically altered strains of the common yeast *Saccharomyces cerevisia*e (the yeast used for ethanol production) can produce butanol through the ABE fermentation process.(44)

In addition to ABE fermentation, other fermentation pathways with proprietary microorganisms are under research and development to produce butanol (n-butanol and other isomers). One project has demonstrated a patented dual-pathway process that eliminates the co-products produced by the ABE fermentation process. This dual-pathway process uses carbohydrates to produce butyric acid in the first stage, which is then converted to butanol in the second stage.(45)

c. Commercialization Status

Biobutanol production is currently being demonstrated in small-scale plants, often in association with universities. BP/DuPont, ButylFuel, and other groups are conducting research and development efforts to improve conversion technology and cost effectiveness. Staff is not aware of any facility producing biobutanol on a commercial basis. Although there are opportunities for breakthroughs, it appears that the technology will not be fully commercialized until sometime after 2020.

Biobutanol could be produced from new plants using corn and sugar crops (sugarcane, sugar beets, sweet sorghum, molasses) or by making modest retrofits to existing ethanol plants. As the technology develops, production of biobutanol could be extended to include lignocellulosic feedstocks.

The Energy Independence and Security Act of 2007 provides an incentive for biobutanol production. The EISA includes butanol or other alcohols as produced through the conversion of organic matter from renewable biomass in the “Advanced Biofuel” category description. EISA definitions specify all corn-based ethanol as a conventional biofuel. However, corn-based butanol would be able to qualify for the Advanced Biofuel category, provided that it was able to meet the 50-percent reduction in lifecycle greenhouse gas performance from baseline gasoline.

3. Carbon Capture and Geologic Sequestration

Carbon capture and geologic sequestration (CCS) is the process of capturing CO_2 and then compressing, transporting, and injecting it into a suitable geologic formation for long-term isolation from the atmosphere. Alternatively, the CO_2 could be sequestered in novel ways, such as industrial fixation of CO_2 into inorganic carbonates. Separation technologies used for carbon capture adsorption, absorption, membranes, cryogenics, and others. The level of development, cost, and efficiencies vary; breakthrough advances would greatly impact CCS viability.

Large stationary sources of carbon dioxide, such as refineries and power plants are most viable candidates for CCS. Gasoline and diesel produced from such refineries could receive lower lifecycle carbon intensity values under the LCFS.

THIS PAGE LEFT INTENIONALLY BLANK

IV. Determination of Carbon Intensity Values

A. Summary

This Chapter describes the methods used to determine the carbon intensity values and presents proposed carbon intensity values for a number of common pathways. This Chapter also presents preliminary data for additional fuel pathways, identifies fuel pathways currently under development, explains the adjustment factors used to account for vehicle power train efficiencies, and discusses the process of accounting for GHG emissions that occur over a period of time rather than at a discrete point in time.

The LCFS regulatory framework builds upon estimates of the carbon intensity (CI) of each fuel pathway. ‘Carbon intensity’ is a measure of the greenhouse gas emissions per unit of fuel energy delivered. In the LCFS regulation, the units used are grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ). Carbon intensity estimates play a key role in determining whether a regulated party has complied with the LCFS rule. Therefore, it is important that the methods used for assigning carbon intensity values accurately reflect the multiple steps involved in producing and using a fuel.

Carbon intensity is determined using lifecycle analysis (LCA). LCA is an analytical method for estimating the aggregate quantity of greenhouse gas emissions from a full fuel cycle. In general, the lifecycle analysis includes the direct effects of producing and using the fuels and “indirect” effects that may be associated with the particular fuel.

The direct effects typically include feedstock generation or extraction; feedstock conversion to finished fuel or fuel blendstock; distribution; storage; delivery; and final use of the finished fuel by the end user. Direct effects are responsible for the generation of several species of GHGs, including CO_2, CH_4, N_2O, VOC and CO. Non-CO_2 species are adjusted to account for their global warming potential, relative to carbon dioxide. The combined global warming potential of all GHGs emitted during the fuel cycle comprise that portion of a fuel’s carbon intensity value attributable to direct effects.

To reflect the full impact of producing and using a fuel, at least some CI values must be adjusted to account for indirect effects that are not among the direct effects captured through LCA. One important indirect effect is land use change. Indirect land use change produces GHG emissions above and beyond those generated during the direct fuel life cycle. In general, a land use change occurs when farmland devoted to food and feed production is diverted into biofuel crop production causing supplies of the displaced food and feed crops to be reduced. Supply reductions cause prices to rise, which, in turn, stimulates increased food and feed production. If that production takes place on land formerly in non-agricultural uses, an indirect land use change impact results. The specific impact consists of the CO_2 released to the atmosphere when converted lands are cleared and the soils disturbed. Although some of these releases are essentially immediate, some continue for several years. Land use change impacts can occur domestically, and in countries that trade with the U.S. Some of the food and feed crops which these trading partners can no longer import from the U.S. are grown on lands converted from non-agricultural to agricultural uses.

Although not specifically calculated as part of the lifecycle analysis, the power train efficiency of the vehicles affects the overall carbon intensity of a fuel and its ultimate use in the LCFS. These adjustments are made using an Energy Economy Ratio (EER). The EER is defined as the ratio of the miles traveled per unit energy input for a fuel of interest to the miles traveled per unit energy for a reference fuel. Each EER is specific to one fuel-vehicle combination. The derivation and use of EERs are described briefly this Chapter and presented in more detail in Appendix C.

Table IV-1 presents a summary of the carbon intensities for a number of pathways for gasoline and fuels that substitute for gasoline. As identified in the table, the carbon intensities have been adjusted by the EERs, where appropriate, to provide an indication of the relative carbon intensities of various pathways. This table does not represent the full range of possible fuels that could be used in the LCFS. As discussed later in this Chapter, staff is continuing to develop carbon intensity values for additional pathways and the proposed regulation itself provides for a public process to modify or add other pathways. Table IV-2 presents similar data for diesel and fuels that substitute for diesel fuel.

The Chapter is divided into three basic sections. The first section discusses the analysis for determining direct effects. The second section discusses the analysis for determining indirect effects. The Chapter concludes with a discussion of the uncertainties associated with the analysis, with an emphasis on the analysis of indirect effects. Appendix C provides additional details supporting the analysis.

Table IV-1
Adjusted Carbon Intensity Values
for Gasoline and Fuels that Substitute for Gasoline

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
		Direct Emissions	Land Use or Other Effect	Total
Gasoline	CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies	95.86	0	95.86
	CaRFG-CARBOB and a blend of 100% average Midwestern corn ethanol to meet a 3.5% oxygen content by weight blend (approximately 10% ethanol)	96.09	---	96.09 [1]
	CaRFG-CARBOB and a blend of an 80% Midwestern average corn ethanol and 20% California corn ethanol (dry mill, wet DGS) to meet a 3.5% oxygen content by weight blend (approximately 10% ethanol)	95.85	---	95.85 [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; 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	47.40	30	77.40
Ethanol from Sugarcane	Brazilian sugarcane using average production processes	27.40	46	73.40
Compressed Natural Gas	California NG via pipeline; compressed in California	67.70	0	67.7 [1]
	North American NG delivered via pipeline; compressed in California	68.00	0	68.00 [1]
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in California	11.26	0	11.26 [1]
Electricity	California average electricity mix	124.10	0	41.37 [2]
	California marginal electricity mix of natural gas and renewable energy sources	104.70	0	34.90 [2]
Hydrogen	Compressed H_2 from central reforming of NG	142.20	0	61.83 [3]
	Liquid H_2 from central reforming of NG	133.00	0	57.83 [3]
	Compressed H_2 from on-site reforming of NG	98.30	0	42.74 [3]
	SB 1505 Scenario; Compressed H_2 from on-site reforming with renewable feedstocks	76.10	0	33.09 [3]

[1] Adjusted by an EER factor of 1.0 to account for no power train efficiency improvements over gasoline engines
[2] Adjusted by an EER factor of 3.0 to account for power train efficiency improvements over gasoline engines
[3] Adjusted by an EER factor of 2.3 to account for power train efficiency improvements over gasoline engines

Table IV-2
Adjusted Carbon Intensity Values
for Diesel and Fuels that Substitute for Diesel

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
		Direct Emissions	Land Use or Other Effect	Total
Diesel	ULSD – based on the average crude oil delivered to California refineries and average California refinery efficiencies	94.71	0	94.71
Compressed Natural Gas	California NG via pipeline; compressed in California	67.70	0	75.22 [1]
	North American NG delivered via pipeline; compressed in California	68.00	0	75.56 [1]
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in California	11.26	0	12.51 [1]
Electricity	California average electricity mix	124.10	0	45.96 [2]
	California marginal electricity mix of natural gas and renewable energy sources	104.70	0	38.78 [2]
Hydrogen	Compressed H_2 from central reforming of NG	142.20	0	74.84 [3]
	Liquid H_2 from central reforming of NG	133.00	0	70.00 [3]
	Compressed H_2 from on-site reforming of NG	98.30	0	51.74 [3]
	SB 1505 Scenario; Compressed H_2 from on-site reforming with renewable feedstocks	76.10	0	40.05 [3]

[1] Adjusted by an EER factor of 0.9 to account for power train efficiency losses compared to diesel engine
[2] Adjusted by an EER factor of 2.7 to account for power train efficiency improvements over heavy-duty diesel engines
[3] Adjusted by an EER factor of 1.9 to account for power train efficiency improvements over heavy-duty diesel engines

B. Direct Effects Analysis

1. Fuel Pathways

Determining the carbon intensity of a particular fuel requires that each step in the production and use of that fuel be fully characterized. These steps comprise the direct effects associated with a fuel pathway. The production of ethanol from corn, for example, involves many steps, each of which contributes to that fuel's ultimate carbon intensity value. Those steps include:

- Farming practices (e.g., frequency and type of fertilizer used);
- Crop yields;
- Harvesting practices;
- Collection and transportation of the crop;
- Type of fuel production process (technology, efficiency of plant/process, etc.);
- Fuel used in the production process (Coal/Natural Gas/Biomass);
- Energy efficiency of the production process;

- The value of co-products generated (e.g. distillers grain);
- Transport and distribution of the fuel; and
- Combustion of the fuel in vehicles.

Once the pathway is fully characterized, the carbon intensities of each of the steps can be summed to generate a fuel's total direct carbon intensity. As discussed in the next section, any effects beyond those included in the direct fuel pathway analysis are then added to the direct effects to obtain the total carbon intensity value for the fuel pathway.

The success of the LCFS at reducing fuel carbon intensity depends upon the extent to which it is able to encourage the development and use of low-carbon alternative fuels. The regulation does not, however, specify which fuels will and will not comply. Instead, the carbon intensities of all fuels, including the reference fuels (gasoline and diesel fuel) are determined, and made available to fuel suppliers for use in determining compliance. Suppliers are free to use these values, or to propose (using a process described in the regulation) different values.

Table IV-3 identifies the fuel pathways that have been completed and are proposed for approval as part of this rulemaking. Note that most of the default fuel pathways include one or more sub-pathways. These sub-pathways provide carbon intensity defaults for fuels produced using processes that deviate somewhat from the process used for the primary pathway. Under the corn ethanol pathway, for example, the sub-pathways identified vary according to the fuel used in the production process (natural gas, coal, biomass), the type of technology used (wet mill or dry mill), and the type of co-product generated (dry distillers grain, wet distillers grain). The supporting documentation for each of these pathways is described in detail on the ARB website and is incorporated by reference into this Staff Report (http://www.arb.ca.gov/fuels/lcfs/lcfs.htm).

Table IV-4 presents other pathways that are under development and references any supporting preliminary documentation that may be available. Pursuant to the proposed regulation, the Executive Officer may approve new or modified pathways following a formal public comment period. New or modified pathways may be developed in response to public comments or staff-identified need. These analyses represent the default values for the LCFS. In addition, as discussed in Chapter V, the proposed regulation allows regulated parties to modify or submit new pathways under specified conditions.

Table IV-3
Fuel Pathways Completed for Use in the LCFS

Fuel Pathway	Description of the Pathway
CARBOB (California Reformulated Gasoline Blendstock for Oxygenate Blending)	1 average pathway based on the average crude oil used in California refineries. http://www.arb.ca.gov/fuels/lcfs/022709lcfs_carbob.pdf
CaRFG (California Reformulated Gasoline)	1 specific pathway combining CARBOB and a blend of an average Midwestern corn ethanol and California corn ethanol to meet a 3.5% oxygen content by weight (approximately 10% ethanol). http://www.arb.ca.gov/fuels/lcfs/022709lcfs_carfg.pdf
Ethanol from Corn	11 different specific pathways that reflect different options that are used to produce ethanol from corn. http://www.arb.ca.gov/fuels/lcfs/022709lcfs_cornetoh.pdf
Ethanol from Sugarcane	1 specific pathway for producing ethanol from sugarcane using average production processes. http://www.arb.ca.gov/fuels/lcfs/022709lcfs_sugarcane.pdf
Electricity	2 specific pathways representing average and marginal electricity used in California. http://www.arb.ca.gov/fuels/lcfs/022709lcfs_elec.pdf
Hydrogen	4 specific pathways reflecting different options to produce hydrogen as a fuel. http://www.arb.ca.gov/fuels/lcfs/022709lcfs_h2.pdf
ULSD (Ultra Low Sulfur Diesel)	1 average pathway based on the average crude oil used in California refineries. http://www.arb.ca.gov/fuels/lcfs/022709lcfs_ulsd.pdf
Compressed Natural Gas	3 specific pathways reflecting different options to produce compressed natural gas as a fuel. http://www.arb.ca.gov/fuels/lcfs/022709lcfs_cng.pdf

Table IV-4
Fuel Pathways Under Development for Use in the LCFS

Fuel Pathway	Description of the Pathway
Ethanol from Sugarcane	Brazilian sugarcane using bagasse for electricity production as a co-product credit
	Brazilian sugarcane using mechanized production of sugarcane
Ethanol from Cellulosic Material	Farmed trees using a fermentation process. Preliminary documentation: http://www.arb.ca.gov/fuels/lcfs/022709lcfs_trees.pdf
	Agriculture Waste
	Forest Waste. Preliminary documentation: http://www.arb.ca.gov/fuels/lcfs/022709lcfs_forestw.pdf
Biodiesel	Midwest soybeans to soy oil for conversion to biodiesel (fatty acid methyl esters - FAME). Preliminary documentation: http://www.arb.ca.gov/fuels/lcfs/022709lcfs_biodiesel.pdf
	Yellow grease, fats, and waste oil for conversion to biodiesel (FAME)[1]
	Palm oil from South East Asia for conversion to biodiesel (FAME)
Renewable Diesel	Midwest soybeans to soy oil for conversion to renewable diesel. Preliminary documentation: http://www.arb.ca.gov/fuels/lcfs/022709lcfs_rd.pdf
	Yellow grease, fats, and waste oil using co-fed stream into refinery or bio-refinery for conversion to renewable diesel[1]
Compressed Natural Gas	Remote LNG shipped to Gulfport, Texas; regasified and pipelined to California; CNG in California.
	Remote LNG shipped to Baja, CA; regasified and pipelined to California; CNG in California.
Crude	Derived from oil sands. Derived from oil shale.
Liquefied Natural Gas	Canadian NG via pipeline to LNG liquefaction facility in California; liquefied in CA for use as LNG.
	Remote LNG shipped to Baja, CA; gasified and pipelined to California; liquefied in California for use as LNG.
	Remote LNG shipped to Baja, CA; LNG trucked to California for use as LNG.
	LNG from landfill gas. http://www.arb.ca.gov/fuels/lcfs/022709lcfs_lpg.pdf

[1] Staff has prepared a very preliminary estimate of 15 gCO_2e/MJ for biodiesel and renewable diesel produced from waste fats and oils. This estimate was used in the diesel compliance scenarios found in Chapter VI, but will not be used for regulatory purposes. Once a revised value, sufficient for use in the Regulation, is available, Staff will publish that value. Details of the preliminary analysis are available on the LCFS website

2. Methodology

As discussed above, an LCA of a transportation fuel evaluates the complete energy use and associated GHG emissions for all steps in fuel production and use cycle. LCA analysis typically consists of two stages. The first evaluates the steps leading up to the dispensing of the finished fuel (or blendstock) into the vehicle's fuel tank. The second stage assesses the combustion of the fuel or fuel blendstock in the vehicle.[26] The following discussion presents the basic methodology for calculating the direct effects and the related carbon intensities for the LCFS fuel pathways.

As discussed in Chapter II, the Energy Commission, in partnership with ARB, developed and adopted the State Alternative Fuels Plan in 2007, pursuant to the requirements of AB 1007. In support of the Plan, the CEC conducted an extensive LCA for transportation fuels under contract with TIAX LLC.(1) This analysis formed the basis for the LCA analyses performed for the LCFS. Since that time, ARB staff has been working closely with the Energy Commission, Life Cycle Associates, TIAX, and other stakeholders to update and augment the LCA done for the State Alternative Fuels Plan. In general, existing pathways have been updated and new pathways added.

For both the AB 1007 effort and the LCFS, the basic analytical tool for identifying and combining the necessary fuel life cycle data and calculating the direct effects has been the "Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation" (GREET) model.(46) Dr. Michael Wang, of the U.S. Department of Energy's Argonne National Laboratory, began developing the GREET model in 1996. Dr. Wang and his colleagues have updated the model several times since then—most recently in September 2008.

For purposes of AB 1007 and the LCFS, the model has been modified to better represent California conditions. This revised version of the Argonne model is referred to as the California-modified GREET (CA-GREET). The version used to determine LCFS fuel carbon intensities is version 1.8b. The CA-GREET model is posted on the ARB website and is incorporated by reference into the Staff Report.(47)

a. General Description of the CA-GREET Model

The CA-GREET model, like the original GREET model, was developed in Microsoft Excel. The CA-GREET Excel spreadsheet is publicly available at no cost. The model is a sophisticated computational spreadsheet, with thousands of inputs and built-in values that feed into the calculation of energy inputs, emissions, carbon intensities, and other values. The model has two parallel branches. The first evaluates the energy use and

---

[26] These two stages are often referred to as Well-to-Tank and Tank-to-Wheels. The Well-to-Tank analysis includes all steps from recovery or production of the feedstock, transport of the feedstock to the production facility, production of the fuel, and blending and transport of the finished fuel to the retail service station for distribution to the vehicle tank. For biofuels, this stage is sometimes referred to as "Seed-to-Tank." The Tank-to-Wheel analysis includes the use of the fuel in an automobile. Together WTT and TTW are combined to create a Well-To-Wheel (WTW) analysis of transportation fuels.

GHG generation from the recovery, production and final use of a fuel in a transportation vehicle (the fuel cycle). A more recent branch addresses the energy used for vehicle production (the vehicle cycle). The GREET fuel cycle evaluation framework was developed using industrial process information from several industries, including agriculture, power generation, and petroleum extraction and refining. This framework establishes the data requirements and the calculations necessary for the determination of energy use, emissions-generation, and—ultimately—fuel carbon intensity. The default values used by the program (many of which can be overridden by the user) are derived from the same sources. For purposes of carbon intensity determination under the LCFS, ARB staff used only the fuel cycle branch of the model. The GREET model has over 100 different fuel pathways and over 70 vehicle/fuel combinations.

In general, each fuel pathway is modeled in GREET as the sum of the GHG emissions resulting from the following sequence of processes:

- Feedstock production (e.g., production of crude for gasoline and diesel, of corn or other biomass for ethanol, etc.);
- Feedstock transportation, storage, and distribution (T&D);
- Fuel production (e.g. gasoline production at refineries, ethanol production at ethanol plants, etc.);
- Fuel transportation, storage, and distribution (T&D); and
- Fuel combustion in a vehicle.

The CA-GREET modifications are mostly related to incorporating California-specific conditions, parameters, and data into the original GREET model. The major changes incorporated into the CA-GREET model are listed below:

- Marine and rail emissions reflect in-port and rail switcher activity with an adjustment factor for urban emissions;
- Natural gas transmission and distribution losses reflect data from California gas utilities;
- The fuel properties data for CARBOB, ultra-low sulfur diesel (ULSD), California reformulated gasoline, natural gas, and hydrogen were revised to reflect California-specific parameters;
- The electricity transmission and distribution loss factor was corrected to reflect California conditions; the electricity mix was also changed to reflect in-State conditions, both for average and marginal electricity mix;
- The California crude oil recovery efficiency was modified to reflect the values specific to the average crude used in California including crude that is both produced in, and imported into, the State (See Appendix C for details);
- Crude refining for both CARBOB and ULSD was adjusted to reflect more stringent standards for these fuels in California;
- Tailpipe CH_4 and N_2O emission factors were adapted for California vehicles where available;
- The process efficiencies and emission factors for equipment were changed to reflect available California-specific data; and

- Landfill gas to CNG pathway was coded into the CA-GREET pathway.

b. Calculation of Carbon Intensity

Carbon intensity as proposed for the regulation is a measure of the greenhouse gas emissions per unit energy of fuel. As discussed earlier, it includes contributions from direct emission for all fuels and from indirect effects for some fuels. Discussed below is the methodology of how carbon intensity is calculated for direct effects using the CA-GREET model. The methodology for indirect effects is presented later in this Chapter.

Figure IV-1
Block Diagram for the various Components for a Fuel Pathway

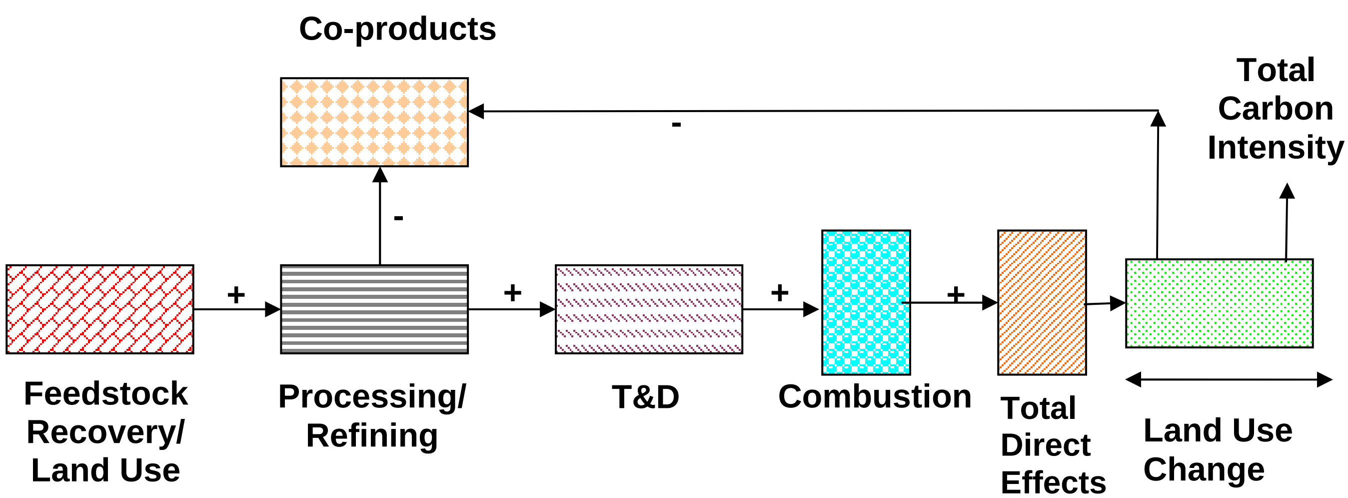


Figure IV-1 presents the components that are representative for either a fossil or biofuel being considered for inclusion under the regulation. The components on the left are those that contribute to the direct emissions and are calculated using the CA-GREET model. The individual components include land use or feedstock recovery (includes farming, crude extraction, transportation of feedstock, etc.), processing (conversion to ethanol, refining to gasoline, etc.), transportation and distribution of the fuel for final use, and use of the fuel in an internal combustion engine. The component on the right includes land use change and is discussed later in this Chapter.

Carbon Intensity for Biofuels:

As an example for biofuel pathway, details of the process of calculating carbon intensity for a corn ethanol pathway is presented below. For corn ethanol, land use includes farming operations, agricultural chemicals production and use, and transport of corn to an ethanol production plant. The CA-GREET model utilizes an average energy use for farming obtained by survey data conducted by the United States Department of

Agriculture (USDA). The average energy use is calculated by using the energy used by individual entities such a tractors, electric motors, etc. This value was determined by conducting a survey of farming practices in several corn farming regions. The CA-GREET model then utilizes the total energy use, the efficiency of energy use (from available published information; for a tractor, it uses published data on fuel economy for an average farm tractor), and the breakdown of energy use by resource (tractor, electric motor, etc.). This information is then combined with emission factors for various pollutants (CO_2, CO, VOC, etc.) obtained from sources such as AP-42, the U. S. EPA's MOBILE6 model, ARB EMFAC Model, Electric Power Research Institute, etc.

This analysis is conducted for all the energy sources to provide total emissions for each of the individual pollutants. For CH_4 and N_2O, the model converts these into CO_2 equivalent using factors published by the Intergovernmental Panel on Climate Change (IPCC)(48). The CA-GREET model also assumes that CO and VOCs are oxidized to CO_2 in the atmosphere and uses factors to convert these into CO_2 equivalent emissions. The CA-GREET pathway documents published on the LCFS detail the conversion factors used. The individual pollutant emissions are then summed up to provide a total for this component.

For agricultural chemicals, the model uses literature data related to production of these chemicals and calculates energy use and attendant emissions derived from the specific energy sources and equipment used for the production and transport of agricultural chemicals to the farm. Survey data (again from the USDA) to estimate average fertilizer, herbicide and pesticide use in farms for producing corn is used by the model to estimate average energy used to produce these chemicals and the resulting emissions from the production of these chemicals.

For transportation, the model utilizes published data on the modes of transporting these to a farm. They include cargo tankers (imports), rail and heavy-duty trucks. Utilizing published data for these modes of transportation and weighted transportation distances, the model calculates the energy needed to transport these to a farm. The attendant GHG emissions are calculated using published emission factors for the different modes of transport. For fertilizers in particular, there are N_2O emissions resulting from the use of nitrogen based fertilizers. The IPCC has estimated average N_2O emissions based on nitrogen application in soil and the model uses this value to estimate N_2O emissions from the use of fertilizers. Use of lime leads to generation of CO_2 from the carbonate and this is directly calculated from the amount of carbonate in the applied lime.

For the processing component, the model utilizes published data for an average ethanol bio-refinery on energy requirements and types of equipment used in the refinery. As explained in the farming component section, the model calculates an average energy use, efficiency of use, and utilizes emission factors from published sources for the different equipment (boilers, turbines, motors, etc.) to calculate total GHG emissions from the production of ethanol (on a per MJ basis).

The next component of the direct emissions shown in Figure IV-1 is co-products. The pathway from feedstock to final fuel production and use involves several processes and operations. These processes have the potential to generate products besides the primary fuel of interest. These additional products are termed co-products. For a current generation ethanol plant, a co-product produced is dry distiller's grain solubles (DDGS). This can be used as a replacement for traditional feed for livestock. A complete lifecycle analysis requires an appropriate GHG credit be provided to the pathway since the use of this co-product will displace the need to produce the displaced product. For corn ethanol, DDGS could replace feed corn that is used as animal feed. The model therefore has provided a GHG credit to the pathway equivalent to producing 1 lb. of feed corn for every lb. of DDGS produced. Appendix C has details of co-product crediting methodologies used in the lifecycle analysis.

For transport and distribution from the ethanol plant, the model uses rail and truck transport for this component. It uses published data on energy use, efficiency, and emissions for rail and trucks using diesel fuel. Distances are estimated based on transport from the Mid-Western U. S. to CA for ethanol produced in the Mid-West. Trucks are considered to distribute the ethanol (blended with CARBOB) to local gas stations. The total from each mode of transport and distribution is summed to calculate a total for this component.

The last component is the actual use of the fuel in an internal combustion engine. For corn ethanol, since the feedstock was produced by 'capturing' CO_2 from the atmosphere, the net CO_2 released from the use of ethanol is considered 'carbon neutral' and assigned a value of zero. Since ethanol is blended with CARBOB for use as California Reformulated Gasoline (CaRFG), tailpipe emissions data (from ARB's EMFAC model, the U. S. EPA's MOBILE6, etc.) from the use of this fuel is used to calculate the GHG impact from the relevant species in tailpipe exhaust. For corn ethanol, a proportional amount is attributed based on the energy contributions of ethanol in CaRFG.

The CA-GREET model then sums the totals from each of the steps detailed above to arrive at a carbon intensity expressed as gCO_2e/MJ. This part is from the direct emissions. For detailed analysis of the corn ethanol pathway, refer to the pathway document on the LCFS website.

Carbon Intensity for Fossil Fuels:

As an example for a fossil fuel pathway, details of the process of calculating carbon intensity for the diesel pathway is presented below. The GREET model utilizes a recovery efficiency based on data published by the Energy Information Administration (EIA), the American Petroleum Institute (API), and other lifecycle studies. For the LCFS, however, staff obtained detailed breakdown of crude slates used in California in 2006 (from the Energy Commission).

Crude slates are generally classified as being primary, secondary, or tertiary, based on the gravity of the recovered crude. The higher the gravity, the lighter the crude and hence the lower the energy use required to recover the crude. Crude recovered in California amounts to approximately 40 percent of all crude delivered to California in 2006. Of the crude produced in California, 40 percent requires tertiary methods to recover the crude and requires steam generation for the process. Therefore, the energy use is higher compared to primary extraction.

Staff used data available from the Department of Oil, Gas and Geothermal Resources (DOOGR) and the Energy Commission to estimate the energy use for crude recovered in California. This was then combined for all crude used in California to compute an average energy use for crude used in California. The energy use was correlated to the types of energy sources utilized (coal, natural gas, etc.) and the corresponding equipment used to generate process energy (turbines, motors, etc.). Emission factors for the various equipment used was obtained from AP-42 (U. S. EPA) and other published sources. The total GHG emissions was then calculated as detailed in the biofuels discussion earlier in this section.

Transport of crude to California refineries is modeled as being delivered by tankers and pipeline. The energy use and corresponding emissions are obtained from published data on tanker capacity, energy consumption, etc. from sources such as the EIA, U.S. EPA and API. Carbon intensity for this component is calculated by correlating energy use for transport with the corresponding mode of transport and emission factors.

For refining, the GREET model uses published data on refining efficiency. Staff used an adjusted refining efficiency from the AB 1007 study(1) which considered stricter fuel specifications in California to require additional energy use translating to a lower efficiency. This efficiency for energy use was correlated to different energy sources and the attendant equipment used to generate process energy and combined with respective emission factors (from AP-42, U. S. EPA, etc.) to calculate total GHG emissions (carbon intensity) for this component.

Transport and use of this fuel is similar to the details provided for corn ethanol. For the combustion of diesel in an internal combustion engine, the carbon content in the fuel (from published sources such as the ARB, U.S. EPA, EIA, API, etc.) is used to estimate the amount of CO_2 generated by complete combustion of the fuel. It then combines this with other tailpipe emission species (from ARB's EMFAC model, the U.S. EPA's MOBILE6, etc.) on a CO_2 equivalent basis to arrive at a total carbon intensity from use in an internal combustion engine. The GHG emissions from all the components described above is summed to estimate carbon intensity for diesel. Complete details of the calculations and pathway are provided in the pathway document for diesel on the LCFS website.

<u>Carbon Intensity for Other Fuels:</u>

For fuels such as electricity and hydrogen, the CA-GREET methodology is similar. It uses data from various sources to estimate average energy use for feedstock production or recovery (uranium mining, natural gas recovery, etc.). The energy use is disaggregated into types of energy sources and the equipment used to generate process energy. These are used to calculate GHG emissions for the recovery of the feedstock for any fuels. As detailed above, transport modes and their emission factors are utilized to calculate GHG emissions for transport of the feedstock. Fuel production efficiencies are estimated from published data (or for new process, modeling tools such as ASPEN(49) is utilized) and combined with energy sources and their respective emission factors to calculate GHG emissions for the production of the fuel. Transport and distribution is also handled as detailed in the discussion for corn ethanol and diesel. For electricity, distribution is handled by attributing transmission losses as the energy losses related to transport and distribution.

The CA-GREET model incorporates several different fuel pathways. However, for the proposed regulation, ARB staff is recommending that only a subset of these pathways be included. Staff is therefore committed to ensuring that all relevant inputs, factors, etc. necessary to compute the carbon intensities of the recommended pathways have been locked into the model and are invariant.

Table IV-5 presents the proposed carbon intensity values that represent the direct emissions part of the Lookup Table for the proposed LCFS regulation. For all the other pathways, until staff proposes the pathways for approval, values, factors, carbon intensities, etc. for these fuel pathways cannot be utilized by stakeholders for compliance with the regulation.

Table IV-5
Proposed Default Carbon Intensity Values for the Direct Pathways

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ) Direct Emissions
Gasoline	CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies	95.86
	CaRFG-CARBOB and a blend of 100% average Midwestern corn ethanol to meet a 3.5% oxygen content by weight blend (approximately 10% ethanol)	96.09
	CaRFG-CARBOB and a blend of an 80% Midwestern average corn ethanol and 20% California corn ethanol (dry mill, wet DGS) to meet a 3.5% oxygen content by weight blend (approximately 10% ethanol)	95.85
Diesel	ULSD – based on the average crude oil delivered to California refineries and average California refinery efficiencies	94.71
Ethanol from Corn	Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	69.40
	California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG	65.66
	California; Dry Mill; Wet DGS; NG	50.70
	Midwest; Dry Mill; Dry DGS, NG	68.40
	Midwest; Wet Mill, 60% NG, 40% coal	75.10
	Midwest; Dry Mill; Wet, DGS	60.10
	California; Dry Mill; Dry DGS, NG	58.90
	Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass	63.60
	Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass	56.80
	California; Dry Mill; Dry DGS; 80% NG; 20% Biomass	54.20
	California; Dry Mill; Wet DGS; 80% NG; 20% Biomass	47.40
Ethanol from Sugarcane	Brazilian sugarcane using average production processes	27.40
Compressed Natural Gas	California NG via pipeline; compressed in California	67.70
	North American NG delivered via pipeline; compressed in California	68.00
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in California	11.26
Electricity	California average electricity mix	124.10
	California marginal electricity mix of natural gas and renewable energy sources	104.70
Hydrogen	Compressed H_2 from central reforming of NG	142.20
	Liquid H_2 from central reforming of NG	133.00
	Compressed H_2 from on-site reforming of NG	98.30
	SB 1505 Scenario; Compressed H_2 from on-site reforming with renewable feedstocks	76.10

c. Adjustments for Vehicle Efficiencies

The carbon intensities of certain fuels need to be adjusted to account for lower (or higher) efficiencies for those fuels relative to baseline fuels when used in a transportation vehicle. This is captured by using an Energy Economy Ratio (EER). The EER is defined as the ratio of the miles traveled per unit energy input for a fuel of interest to the miles traveled per unit energy for a reference fuel. For light duty vehicles, gasoline is the reference fuel. For heavy duty vehicles, diesel is the reference fuel. The EER for each type of light duty alternative fuel vehicle was calculated by dividing the fuel economy for that vehicle by the fuel economy for a corresponding gasoline vehicle that is most similar in size and style, referred to as the reference vehicle. EERs were calculated using test data using the fuel of interest and the reference fuel in similar engines. For areas where data was either lacking or insufficient, EERs were estimated using engineering analysis. Table IV-6 shows the use of EERs for fuels when they substitute for gasoline and diesel in light, medium and heavy duty vehicles. Complete details of the EER calculations are provided in Appendix C.

Table IV-6
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 / ICEV	1.0	CNG or LNG	0.9
Electricity / BEV, or PHEV	3.0	Electricity / BEV, or PHEV	2.7
H2 / FCV	2.3	H2 / FCV	1.9

(BEV = battery electric vehicle, PHEV=plug-in hybrid electric vehicle, FCV = fuel cell vehicle)

C. Indirect Effects Analysis

The lifecycle GHG-generating effects described in Section A, above result directly from the production, transport, storage, and use of a fuel. In addition to these direct effects, some fuel production processes generate GHGs *indirectly*, via intermediate market mechanisms. If, for example, the propulsion system of an advanced vehicle requires a certain metal that is surfaced-mined in remote forested areas, the increased demand for that propulsion system would increase the demand for the required metal. Meeting that demand would result in the expansion of the mines that supply the ore for that metal. Expansion of the mines would require the clearing of forests, and the disturbance of underlying soils—both of which release GHGs to the atmosphere.

Stakeholders participating in the LCFS process have suggested that most or all transportation fuels generate varying levels of indirect GHG emissions. To date, however, ARB staff has only identified one indirect effect that generates significant quantities of GHGs: land use change effects. A land use change effect is initially triggered by a significant increase in the demand for a crop-based biofuel. When farmland devoted to food and feed production is diverted to the production of that biofuel crop, supplies of the displaced food and feed crops are reduced. Supply reductions cause prices to rise, which, in turn, stimulates increased production. If that production takes place on land formerly in non-agricultural uses, a land use change impact results. The specific impact consists of the carbon released to the atmosphere from the lost cover vegetation and disturbed soils in the periods following the land use conversion. This section describes how ARB estimates the land use change impacts of biofuel crop production, and summarizes the impact estimates obtained to date.

1. Overview

Increasing worldwide demand for biofuels will stimulate a corresponding increase in the price and demand for the crops used to produce those fuels. To meet that demand, farmers can:

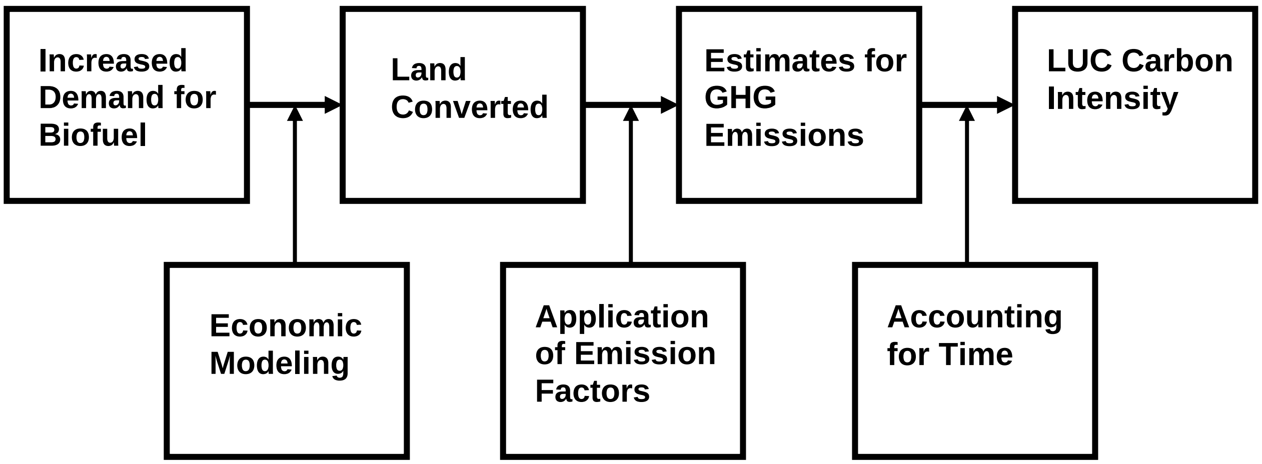
- Grow more biofuel feedstock crops on existing crop land by reducing or eliminating crop rotations, fallow periods, and other practices which improve soil conditions but reduce the number of harvests over time;
- Convert existing agricultural lands from food to fuel crop production;
- Convert lands in non-agricultural uses to fuel crop production; or
- Take steps to increase yields beyond that which would otherwise occur.

Land use change effects occur when the acreage of agricultural production is expanded to support increased biofuel production. Lands in both agricultural and non-agricultural uses may be converted to the cultivation of biofuel crops. Some land use change impacts are indirect or secondary. When biofuel crops are grown on acreage formerly devoted to food and livestock feed production, supplies of the affected food and feed commodities are reduced. These reduced supplies lead to increased prices, which, in turn, stimulate the conversion of non-agricultural lands to agricultural uses. The land conversions may occur both domestically and internationally as trading partners attempt to make up for reduced imports from the United States. The land use change will result in increased GHG emissions from the release of carbon sequestered in soils and land cover vegetation. These emissions constitute the land use change impact of increased biofuel production.

Not all biofuels have been linked to indirect land use change impacts. The use of corn stover as a feedstock for cellulosic ethanol production, for example, is not likely to produce a land use change effect. Feedstocks such as native grasses grown on land that is not suitable for agricultural production are unlikely to cause land use change impacts. Waste stream feedstocks such yellow grease, waste cooking oils and municipal solid waste, are also unlikely to lead to land use change impacts. Staff is in the process of identifying feedstocks that have no measurable land use change impacts.

Figure IV-2 depicts the process used to quantify the GHG emissions from land use change and to convert those emissions to a carbon intensity value that can be added to a fuel's direct carbon intensity value.

Figure IV-2
Land Use Change Impact Estimation Process



Estimating how much non-agricultural land is converted to agricultural uses in response to increased demand for biofuels requires a model capable of simulating the multiple economic forces driving the land use change process. Models of the international agricultural system have been adapted to estimate the magnitude of biofuel-driven land use change impacts. The GHG emissions generated by the conversion of land to agricultural uses are estimated by applying emission factors to the acreage of land converted. Emission factors are estimates of the GHGs released from each converted unit of land area. GHGs are released from burned or decomposing cover vegetation and disturbed soils. Land use change emissions vary substantially with time. Large initial releases of GHGs from clearing native vegetation are followed by slower releases from below-ground materials. The time-varying emission flows are converted to a land use change carbon intensity value using a time accounting model.

In Section 2, we discuss the choice of an economic model, key inputs to that model, the application of emission factors, and the process of accounting for time. Modeling results for corn and sugarcane ethanol, soy biodiesel, and cellulosic material are presented in Section 3, followed by a brief discussion of ongoing analyses in Section 4. Note that the results for soy biodiesel and cellulosic material are preliminary.

2. Methodology

a. Selection of the Estimation Model

The land use change effects of a large expansion in biofuel production will occur both domestically and internationally. A sufficiently large increase in biofuel demand in the U.S. will cause non-agricultural land to be converted to crop land both in the U.S. and in countries with agricultural trade relations with the U.S. Models used to estimate land use change impacts must, therefore, be international in scope. In cooperation with researchers from the University of California, Berkeley (UCB) and Purdue University, ARB staff chose the Global Trade Analysis Project (GTAP) model for conducting the analysis. Other models considered are discussed in Appendix C.

The GTAP is a computable general equilibrium (CGE) model developed and supported by researchers at Purdue University. Within the GTAP's scope are 111 world regions, some of which consist of single countries, others of which are comprised of multiple neighboring countries. Each region contains data tables that describe every national economy in that region, as well as all significant intra- and inter-regional trade relationships. The data for this model is contributed and maintained by more than 6,000 local experts.

The GTAP has been extended for use in land-use change modeling by adding land use data on 18 worldwide agro-ecological zones, a carbon emissions factor table, and a co-products table (which adjusts GHG emission impacts based on the market displacement effects of co-products such as the dried distillers' grains with soluble—an ethanol production co-product). Predicted land use change impacts are aggregated by affected land use type (forest, and pasture).

The GTAP has a global scope, is publicly available, and has a long history of use in modeling complex international economic effects. Therefore, ARB staff determined that the GTAP is the most suitable model for estimating the land use change impacts of the crop based biofuels that will be regulated under the LCFS. The GTAP is relatively mature, having been frequently tested on large-scale economic and policy issues. It has been used to assess the impacts of a variety of international economic initiatives, dating back to the Uruguay and Doha Rounds of the World Trade Organization's General Agreement on Tariffs and Trade.[27] More recently, it has been used to examine the expansion of the European Union, regional trade agreements, and multi-national climate change accords. A detailed discussion of the indirect land use change model selection process is provided in Appendix C.

---

[27] The Uruguay Round began in September of 1986 and concluded in April, 1994. The Doha Round began in November of 2001 and is ongoing.

b. Key Inputs to GTAP

The primary input to computable general equilibrium models such as GTAP is the specification of the changes that will, by moving the economy away from equilibrium, result in the establishment of a new equilibrium. Parameters such as elasticities are used to estimate the extent which introduced changes alter the prior equilibrium. Listed below are the inputs and parameters that the GTAP uses to model the land use change impacts of increased biofuel production levels.

- Baseline year: GTAP employs the 2001 world economic database as the analytical baseline. This is the most recent year for which a complete global land use database exists.

- Fuel production increase: The primary input to computable general equilibrium models such as GTAP is the specification of the changes that will result in a new equilibrium.

- Land use change analysis: The primary input is the change in biofuel production expected to occur in response to federal energy legislation and GHG emission regulations such as the LCFS.

- Crop yield elasticity: This parameter determines how much the crop yield will increase in response to a price increase for the crop. Agricultural crop land is more intensively managed for higher priced crops. If the crop yield elasticity is 0.25, a P percent increase in the price of the crop relative to input cost will result in a percentage increase in crop yields equal to P times 0.25. The higher the elasticity, the greater the yield increases in response to a price increase.

- Elasticity of crop yields with respect to area expansion: This parameter expresses the yields that will be realized from newly converted lands relative to yields on acreage previously devoted to that crop. Because almost all of the land that is well-suited to crop production has already been converted to agricultural uses, yields on newly converted lands are almost always lower than corresponding yields on existing crop lands.

- Elasticity of harvested acreage response: This parameter expresses the extent to which changes occur in cropping patterns of existing agricultural land as land costs change. The higher the value, the more cropping patterns will change (e.g. soybean to corn) in response to land costs.

- Elasticity of land transformation across cropland, pasture and forest land: This elasticity expresses the extent to which expansion into forestland and pastureland occurs due to increased demand for agricultural land (driven by higher crop prices).

- Trade elasticity of crops: These elasticity values express the likelihood of substitution among imports from all available exporters. They express the extent to which an importer will respond to a price increase for a given commodity by switching to a different exporter who can supply the commodity at a lower price.

c. Land Conversion Emission Factors

GTAP modeling provides an estimate for the amounts and types of land across the globe that is converted to agricultural production as a result of the increased demand for biofuels. The next step in calculating an estimate for GHG emissions resulting from land conversion is to apply a set of emission factors. Emission factors provide average values of emissions per unit land area for carbon stored above and below ground as well as the annual amount of carbon sequestered by native vegetation. The amount of "lost sequestration capacity" per unit land area results from the conversion of native vegetation to crops. This value may be significant for areas with rapidly growing forests. Staff has chosen to use emission factor data from Searchinger et al. (2008)[28]. These emission factors—known as the "Woods Hole" data—include data on a wide variety of terrestrial ecosystems. A spreadsheet detailing emission factors used for the LCFS is located at http://www.arb.ca.gov/fuels/lcfs/ef_tables.xls.

In applying the Woods Hole emission factors, ARB assumed that 90 percent of the above-ground and 25 percent of the below-ground carbon is emitted over the fuel production period (50-52). The carbon that would have been sequestered in the lost cover vegetation is also included in the total emissions value. Applying these assumptions to the locations, types and amounts of land conversion predicted by GTAP, staff calculated estimates of the total GHG emissions from those converted land areas.

These land use change emissions totals are used to derive the carbon intensity values appearing in the LCFS Lookup Tables. Some of the available methods for converting emissions totals to carbon intensities take time-varying emissions profiles into consideration. These methods are discussed in the next section.

d. Accounting for GHG Emissions That Occur Over Time

As we discussed in section c above, the conversion of forest, grassland, or pasture to agricultural uses releases much of the carbon stored in these ecosystems. The releases happen over a period of years, as follows:

- An initial GHG burst from burning and/or decaying cover vegetation; this is referred to as the above ground release;
- A slower release of carbon from disturbed soils: larger emissions occur during the first few years, followed by declining releases. This process is referred to as the below-ground release; and

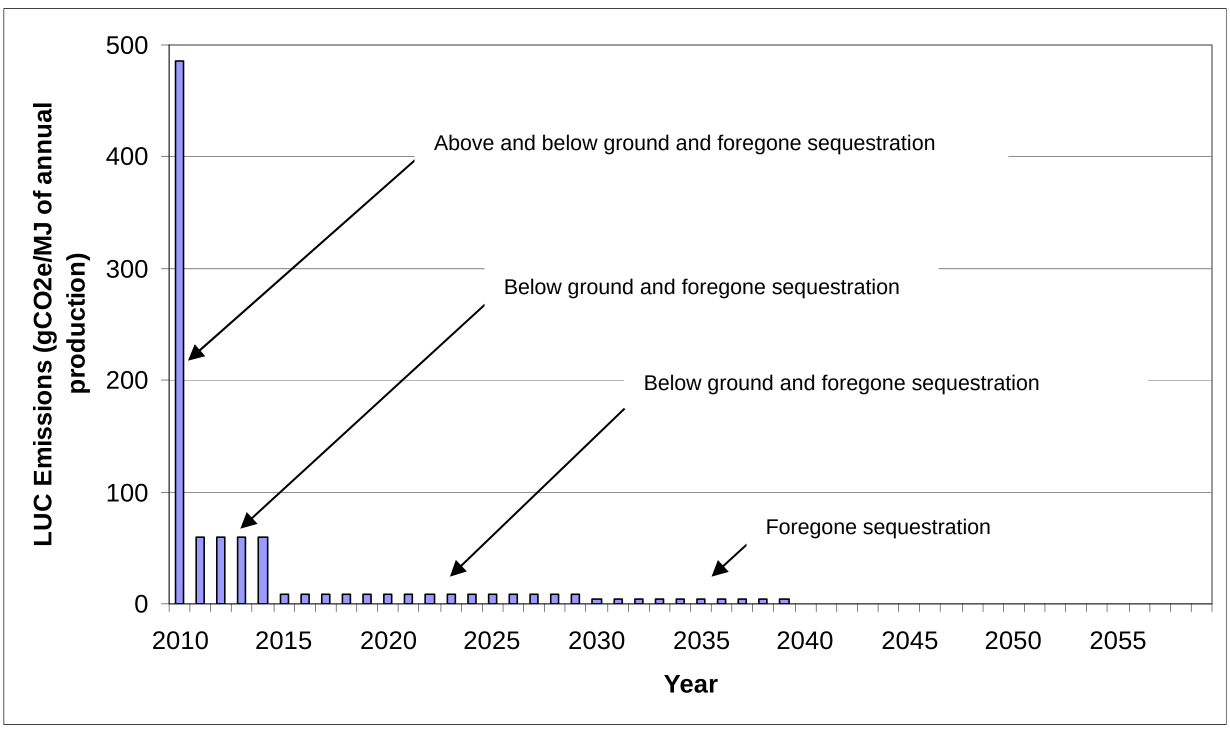
[28] This data set is referred to as the "Woods Hole" data because it was compiled by Searchinger's co-author, R. A. Houghton, who is affiliated with the Woods Hole Oceanographic Institute.

- Loss of the carbon sequestration capacity of the cleared vegetation.

Figure IV-3 shows a representative time-profile for emissions resulting from land use change assuming a project start date of 2010 and an end date of 2040. The above and below-ground emissions and foregone sequestration values used in these scenarios are for illustrative purposes only and are not final LCFS values. The spreadsheet used to perform these calculations is available at http://www.arb.ca.gov/fuels/lcfs/btime1-1_arb.xls.(53) The land use change emissions profile depicted in Figure IV-3 assumes that:

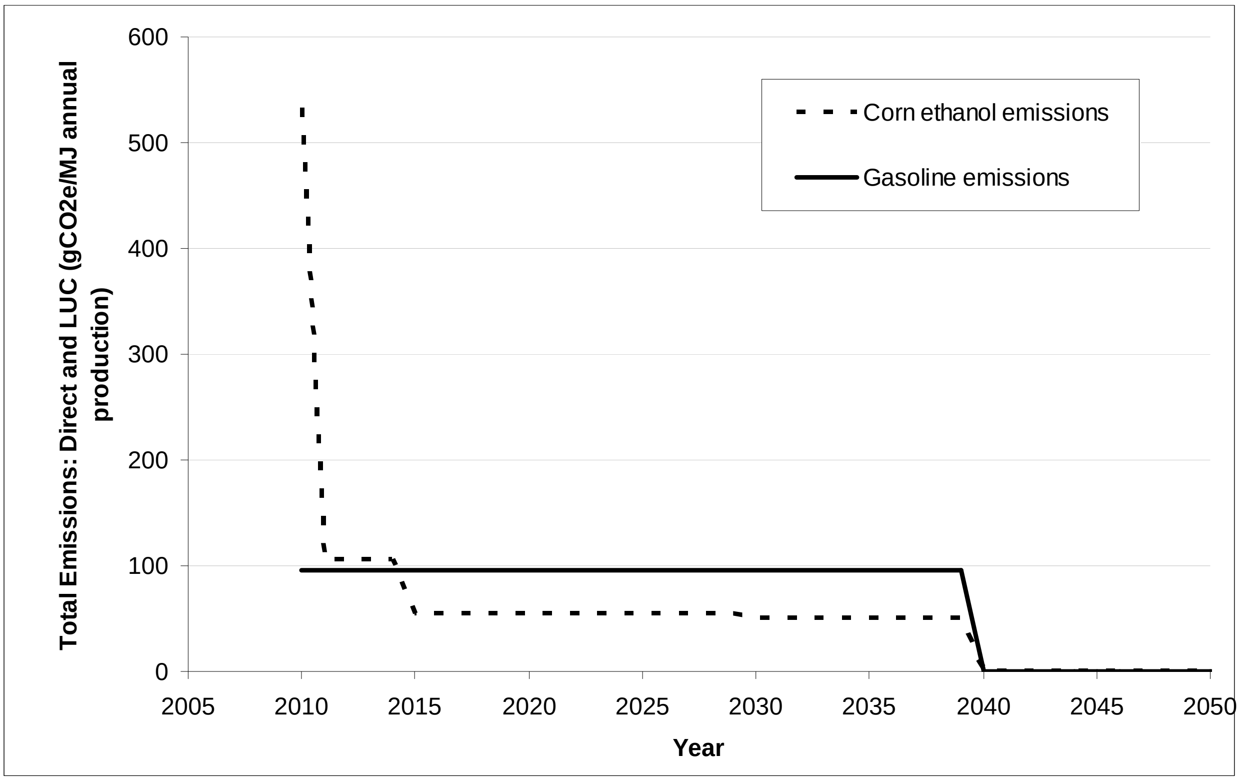
- All above-ground carbon is released in year one due to burning of native vegetation to clear the land for cultivation;
- The majority of below-ground release occurs over the first five years followed by a much slower release over the next 15 years; and
- Forgone sequestration occurs over the entire project period.

Figure IV-3
Representative Land Use Change Emissions Profile



Calculating the carbon intensity for a crop based biofuel (e.g. corn ethanol) requires that time-varying emissions be accounted for in a manner that allows meaningful comparison with the carbon intensity of a reference fuel (e.g. gasoline displaced by the biofuel) which releases greenhouse gases at a relatively constant rate over the years in which it is used. Figure IV-4 shows a representative comparison of gasoline emissions to total biofuel emissions (direct emissions and land use change emissions). To compare emissions for the two fuels in the LCFS, we need to convert the time-varying biofuel emissions into an equivalent series of constant annual emissions.

Figure IV-4
Comparison of Corn Ethanol and Gasoline Total Emissions



Four aspects critical to such an analysis are presented below.

- Estimating the time distribution of emission of greenhouse gases resulting from land use change predicted by the GTAP model.
- Establishing a timeframe over which a biofuel will likely be utilized within the LCFS (project horizon). This value is very important as it determines how long a biofuel has to "pay back" the land use change emissions it generates. For corn ethanol and other crop-based biofuels, staff has assumed project horizons of 20 to 30 years. Specification of the project time horizon is important because the GHG costs and benefits of a crop-based biofuel 'project' accrue at very different rates through time. Most of the costs generated by land use change events accrue within the first two years of project initiation. The benefits are relatively low, and accrue at a more or less constant rate through time. The longer the project time horizon, the more time the benefits have to catch up with the costs. Because crop-based biofuels do not begin yielding net benefits for many years,

ARB staff anticipate that they will be displaced relatively quickly by fuels that provide greater benefits and do so earlier in their project lifetimes.

- Establishing the impact horizon. The impact horizon gives the period of time or the point in the future at which we desire to compare the relative global warming effects of different fuels. Choosing a short impact horizon (e.g. 20 to 30 years) places an emphasis on achieving early emissions reductions which may be appropriate if one assumes that irreversible effects of global climate change may occur if GHG emissions are not reduced quickly. Staff has evaluated impact horizons ranging from 10 to 100 years.
- Establishing a weighting or discounting scheme that captures the relative global warming effect of greenhouse gases released at different times and converting that information into a meaningful single value that reasonably reflects the carbon intensity attributable to a fuel's land use change effects. ARB staff considered three different schemes to account for time when calculating land use change impacts for biofuels.

  The first time accounting method staff considered is an averaging approach which sums all land-use-change-induced carbon emissions over the project period, and then divides that value by the total fuel production (measured on an energy basis) over the assumed project horizon. The resulting land use change carbon intensity value is then added to the fuel's direct carbon intensity value. This sum is the fuel's total carbon intensity under the LCFS. This method is referred to as "annualization" in this Staff Report.

  The second method utilizes a net present value (NPV) calculation to discount future emissions so that a ton of emissions occurring today is weighted more heavily than a ton of emissions occurring in the future.

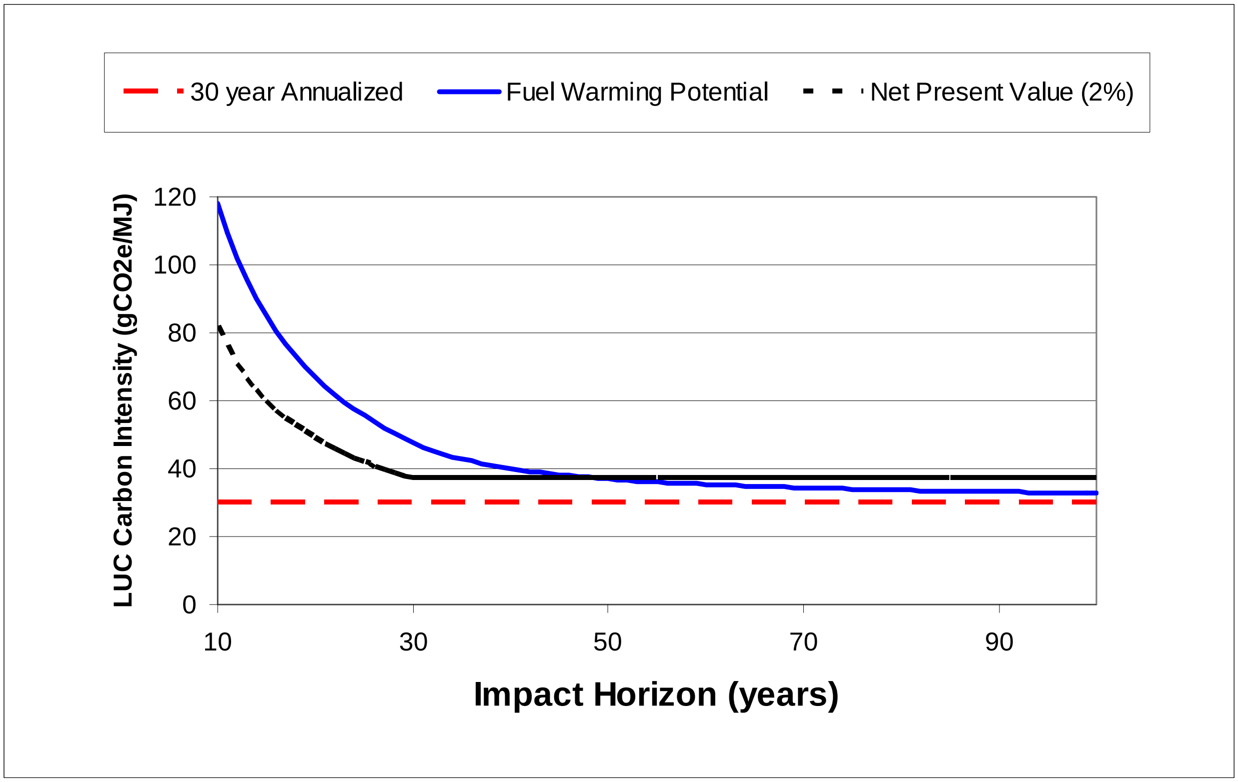
  The third method—developed by researchers at the University of California, Berkeley and the Union of Concerned Scientists(53)—calculates the Fuel Warming Potential (FWP) of GHG emissions. The FWP is the cumulative atmospheric warming effect of the emissions released over the assumed impact horizon.

  A more detailed discussion of these three methods is provided in Appendix C.

<u>Comparison of Time Accounting Methods:</u>

Figure IV-5 compares the three time accounting methods considered by ARB staff. In this figure, the "additional" carbon intensity resulting from land use change emissions is plotted over the impact time horizon. The emissions plotted in this Figure are calculated from the same data that was used in Figure IV-3.

Figure IV-5
Comparison of Time Accounting Methods



These plots show that both the FWP and NPV methods result in larger carbon intensity values than the 30-year annualized method. This is to be expected because both methods weight early carbon dioxide emissions more than later emissions while the annualized method treats all emissions over the project horizon as being equivalent. The FWP and NPV methods also result in the calculation of large land use change carbon intensity values for short impact horizons due to the large up-front emissions associated with land use change. When calculated using the annualized method, carbon intensity is a function only of the project horizon: because it is independent of the impact horizon, the annualized carbon intensity value is constant over all impact horizon lengths. However, the same is not true for the project horizon. As the length of the project horizon decreases, the annualized carbon intensity value increases.

Choosing an Appropriate Accounting Method:

The land use change intensity values depicted in Figure IV-5 for impact horizons of 30 and 50 years are summarized below in Table IV-7.

Table IV-7
Land Use Change Carbon Intensity Values for Three Accounting Methods

Accounting Method	Project Horizon (years)	Impact Horizon (years)	LUC CI (gCO_{2e}/MJ)
Annualized	30	N/A	30
NPV (2%)	30	30 or more	37
FWP	30	30	48
FWP	30	50	37

The NPV method (using a 2% discount rate) yields a higher land use change impact estimate than the 30-year annualized method. This estimate is dependent on the choice of a discount rate. Choosing a discount rate of 5% would produce a significantly different (higher) value. Unfortunately, the relationship between the timing of GHG emissions and the damages caused by those emissions has not been established. Even if this relationship had been defined, a further relationship between damages and the choice of a discount rate would have to be worked out. This second relationship presents significant challenges because discounting was developed to evaluate flows of financial or economic values. Applying this technique to physical flows is far from straightforward. Given these difficulties, ARB staff ruled out the use of the NPV method in determining LCFS carbon intensity values.

The FWP method, on the other hand, was designed to capture the relative atmospheric warming impacts of time-varying land use change emissions, given the choice of an appropriate impact horizon. For a 30 year impact horizon, the FWP method yields a land use change carbon intensity value higher than the annualized value. For a 50 year impact horizon, the FWP method yields a land use change carbon intensity value which is much closer to—but still higher than—the annualized value. As the length of the impact horizon increases, the two values continue to converge.

Of the three methods, annualization is the simplest to apply: it does not depend upon the development of an emissions time profile. Total emissions are simply allocated equally over all project horizon time periods. All that is required, therefore, is an estimate of the total emissions attributable to land use change, and the total fuel production (on an energy basis) over the assumed project horizon. As long as the project horizon used in the analysis is not overly long (no longer than about 30 years), this method is reasonable to use. With longer time periods, the use of a method that weights earlier emissions becomes necessary. A detailed discussion of the issues that must be considered when choosing a time accounting method can be found in Appendix C.

For calculating land use change carbon intensity, ARB staff has chosen to use the annualized method. Staff will continue to analyze the FWP method, however, and may reconsider this decision after a more thorough analysis has been completed.

3. Results and Discussion of Land Use Change Effects

In this section, we present land use change impact modeling results for corn and sugarcane ethanol. Results for each fuel include a sensitivity analysis performed on key model inputs. All land use change carbon intensity values were calculated using the annualized method and a 30 year project horizon.

a. Indirect Effects: Land Use Change Effects for Corn Ethanol

The corn ethanol land use change results presented in this section were produced using the GTAP global economic model. Table IV- 8 summarizes the key inputs for the GTAP analysis. The parameters appearing in this table are described in Appendix C.

Table IV-8
Key Inputs into the GTAP Model

Inputs/Parameters	Ranges (if appropriate)
Baseline Year	2001
EtOH production increase (billion gallons)	13.25 *
Crop Yield Elasticity	0.1 to 0.6
Elasticity of Harvested Acreage Response	0.5
Elasticity of land transformation	0.1 to 0.3
Elasticity of crop yields with respect to area expansion	0.25 to 0.75
Trade elasticity	1 Std. Dev. Below and 1 Std. Dev. Above the Central Value

* One sensitivity analysis run used 8.25 billion gallons

<u>Parameters that affect corn ethanol results from GTAP:</u>

GTAP employed the 2001 world economic database as the analytical baseline. This is the most recent year for which a complete global land use database exists. In order to assess the relative influence of each model input on model outputs (land conversion totals and GHG emissions), staff conducted a sensitivity analysis. To test the model's sensitivity to a given input parameter, the modeler completes a series of runs in which the input parameter is varied across its full range. All other input values are held constant.

An ethanol production increase of 13.25 billion gallons was assumed for all but one of the modeling runs. This production increment corresponds to increasing U.S. corn ethanol production from 1.75 billion gallons in produced 2001 to the 15 billion gallon volume authorized by the Energy Independence and Security Act of 2007 (EISA). The sensitivity of the model output to this parameter was assessed by performing a run in which the ethanol production increase was set at 8.25 billion gallons. The *crop yield elasticity* (elasticities are described in Appendix C) was varied from 0.1 to 0.6. Based on a review of the literature on corn yields, the historical average yield response in the

U.S. had been 0.4. However, there is evidence that the corn yield elasticity has been falling over time; the most recent study produced a yield response of 0.27(54). The GTAP modelers applied a relatively high value of 0.5 for the *elasticity of harvested acreage response*. The higher the value, the more cropping patterns will change (e.g. soybean to corn) in response to land costs. Variation in this value is known to have little effect on GHG emission estimates; it was therefore not included in the sensitivity analysis. Because the available evidence indicates that land use changes across agricultural, forest, and pasture cover types are not readily triggered by changes in land costs, the *elasticity of land transformation across cropland, pasture, and forestry* was set to the relatively low value of 0.2 and for the sensitivity analysis it was varied between 0.1 and 0.3.

The *elasticity of crop yields with respect to area expansion* expresses the yields that will be realized from newly converted lands relative to yields on acreage previously devoted to that crop. Based on the best available professional judgment of those with experience in this area, the modelers selected a value of 0.50. For purposes of the sensitivity analysis, this parameter was varied from 0.25 to 0.75. GTAP modelers estimated the *trade elasticity values* based on an analysis of bilateral trade data from a variety of nations in the western hemisphere. The central trade elasticity values are presented in Appendix C along with the sensitivity analysis ranges of one standard deviation below and one standard deviation above the central values.

Table IV-9 shows sensitivity analysis results obtained by independently varying the corn ethanol production increase and elasticity inputs to the model and tracking the percentage change in land use change carbon intensity (from low input value to high input value). Sensitivities are critical to assess the performance of a model in providing reasonable outputs relative to variation in input values. As an example, if outputs are highly sensitive to the volume of ethanol production increase, then the modelers would have to consider using a change that could be reasonably expected over a shorter time period. As seen in the analysis here for corn ethanol, input production volumes resulted in insignificant changes in model outputs. Variation of some of the elasticity parameters resulted in moderate to significant changes in the outputs. More detailed discussion of these is provided in Appendix C.

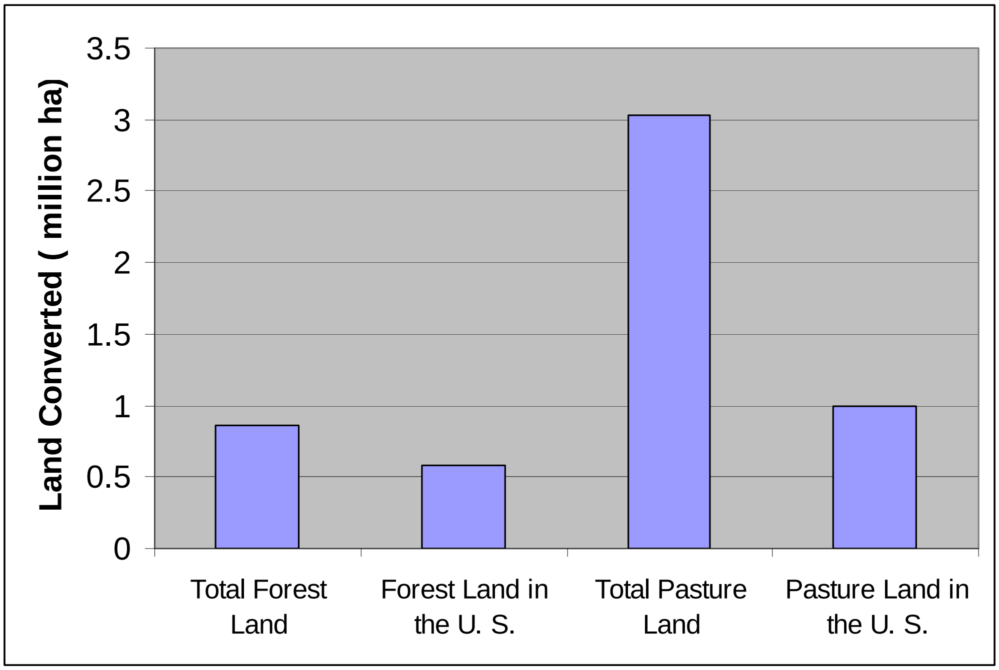
Table IV-9
Sensitivity Analysis Results for Corn Ethanol

Input variable	Input Variable Ranges		Percent Change in LUC Carbon Intensity
	Low Value	High Value	
EtOH production increase (billion gallons)	8.25	13.25	2
Crop Yield Elasticity	0.1	0.6	-49
Elasticity of Harvested Acreage Response	0.5	0.5	Not varied
Elasticity of land transformation	0.1	0.3	30
Elasticity of crop yields w.r.t. area expansion	0.25	0.75	-77
Trade elasticity	1 Std. Dev. Below	1 Std. Dev. Above	-2

Adjustment of GTAP Model Results:

Because the modeling runs used a baseline year of 2001, the model output corresponds to a new equilibrium achieved in 2001 after introducing a 13.25 billion gallon increase in corn ethanol production. These results must be corrected for the changes in agriculture that have occurred between 2001 and present. The change that most significantly affects model output is an increase in crop yields. In 2001, the average corn yield in the U.S. was 138.2 bushels per acre(55) and the average corn yield for 2006 to 2008 was 151.3 bushels per acre which represents a 9.5% increase over 2001. We used a three year average because yields can fluctuate significantly on a year to year basis. An adjustment for this yield increase was applied to the model results. The model itself was not modified and re-run. Figure IV-6 below shows the "adjusted" land conversions for corn ethanol as predicted by the GTAP model for an increase in ethanol production of 13.25 billion gallons.

Figure IV-6
Average Land Conversions Predicted by the Model for Corn Ethanol



<u>Calculating the Land Use Change Carbon Intensity for Corn Ethanol:</u>

In order to select an appropriate central value for the land use change impact of corn ethanol production, staff narrowed down the range of values from the sensitivity analysis by removing the results obtained from the most improbable combinations of input elasticity values. These variables, and the narrowed, 'most reasonable' ranges used are:

- Elasticity of crop yield with respect to area expansion: 0.5 to 0.75;
- Crop yield elasticity: 0.2 to 0.4;
- Elasticity of land transformation: 0.1 to 0.3; and
- Trade elasticity: central case.

The seven sensitivity runs that remained following the exclusion of runs outside of the above ranges are shown in Table IV-10. As shown in the rightmost column of Table IV-10, the mean global land conversion value across this narrowed range of runs is 3.89 million hectares. When the total GHG emissions from the conversion of these lands are annualized ove r a 30-year period, the result is a mean land use change impact of 30 gCO_2e/MJ.

Table IV-10
GTAP Modeling Results for Corn Ethanol Land Use Change

Scenario	A	B	C	D	E	F	G	Mean
Economic Inputs								
EtOH production increase (bill. gal.)	13.25	13.25	13.25	13.25	13.25	13.25	13.25	
Elasticity of crop yields wrt area expansion	0.5	0.75	0.5	0.5	0.5	0.66	0.75	
Crop yield elasticity	0.4	0.4	0.2	0.4	0.4	0.25	0.2	
Elasticity of land transformation	0.2	0.2	0.2	0.3	0.1	0.2	0.2	
Elasticity of harvested acreage response	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Trade elasticity of crops	See Appendix C							
Model Results								
Total land converted (million ha)	4.03	2.68	5.48	4.56	3.01	3.83	3.66	**3.89**
• Forest land (million ha)	1.04	0.37	1.46	0.89	1.00	0.73	0.55	**0.86**
• Pasture land (million ha)	3.00	2.32	4.02	3.65	2.01	3.10	3.10	**3.03**
U.S. land converted (million ha)	1.74	1.16	2.01	2.12	1.14	1.46	1.32	**1.56**
• U.S. forest land (million ha)	0.70	0.36	0.82	0.81	0.48	0.46	0.40	**0.58**
• U.S. pasture land (million ha)	1.04	0.79	1.19	1.31	0.66	1.00	0.92	**0.99**
LUC carbon intensity (gCO_{2e}/MJ)	33.6	18.3	44.3	35.3	27.1	27.4	24.1	**30**

The 30-year annualized value for carbon intensity (30 gCO_2e/MJ) differs from the value previously reported by ARB in October (35 gCO_2e/MJ). As discussed previously, our current analysis removes the results obtained from the most improbable combinations of input elasticity values by establishing "most reasonable" ranges for these elasticity values. As reflected in the sensitivity analysis, GTAP model output is most sensitive to the *elasticity of crop yields with respect to area expansion*. A major concern expressed about our October result was that the range chosen for this parameter (0.25 to 0.75) extended too low. ARB agreed with this opinion and has excluded all modeling runs for which this elasticity was less than 0.5. Application of these new elasticity criteria reduces the carbon intensity from 35 to 32.9 gCO_2e/MJ. The carbon intensity value is further reduced to 30 gCO_2e/MJ by applying the external adjustment for increase in corn yield.

b. Indirect Effects: Land Use Change Effects for Sugarcane Ethanol

Like the corn ethanol results presented above, the sugarcane ethanol land use change results presented in this section were produced using GTAP with a 2001 baseline. The results simulate the GHG-generation impacts of an increase in Brazilian sugarcane ethanol production from 3.61 billion gallons to 5.61 billion gallons. Model outputs were updated to reflect the 8.2% increase in Brazilian sugarcane yields observed between 2001 and the average for the 2006-2008 time period(56). Sensitivity analyses were performed for sugarcane ethanol as described in the preceding corn ethanol discussion. The results are shown in Table IV-11. More complete details are available in Appendix C.

Table IV-11
Sensitivity Analysis Results for Sugarcane Ethanol

Input variable	Input Variable Ranges		Percent Change in LUC Carbon Intensity
	Low Value	High Value	
EtOH production increase (billion gallons)	2.00	2.00	Not varied
Crop Yield Elasticity	0.1	0.5	-34
Elasticity of Harvested Acreage Response	0.5	0.5	Not varied
Elasticity of land transformation	0.1	0.3	15
Elasticity of crop yields with respect to area expansion	0.25	0.75	-76
Trade elasticity	1 Std. Dev. Below	1 Std. Dev. Above	-3

In order to select an appropriate central value for the indirect land use change impact of sugarcane ethanol production, staff narrowed down the range of values from the sensitivity analysis by removing the results obtained from the most improbable combinations of input elasticity values. These variables, and the narrowed, 'most reasonable' ranges used are:

- Elasticity of crop yield with respect to area expansion: 0.5 to 0.75 (0.80 for Brazil);
- Crop yield elasticity: 0.20 to 0.40;
- Elasticity of land transformation: 0.1 to 0.3; and
- Trade elasticity: central case.

The five sensitivity runs that remained following the exclusion of runs outside of the above ranges are shown in Table IV-12. As shown in the rightmost column of Table IV-12, the mean global land conversion value across this narrowed range of runs is 1.09 million hectares. When the total GHG emissions from the conversion of these lands are annualized over a 30-year period, the result is a mean indirect land use change impact of 46 gCO_2e/MJ.

Table IV-12
GTAP Modeling Results for Sugarcane Ethanol Land Use Change

Scenario	**A**	**B**	**C**	**D**	**E**	**Mean**
Economic Inputs						
EtOH production increase (bill. gal.)	2.00	2.00	2.00	2.00	2.00	
Elasticity of crop yields wrt area expansion	0.50	0.75	0.50	0.50	*	
Crop yield elasticity	0.25	0.25	0.25	0.25	0.25	
Elasticity of land transformation	0.20	0.20	0.30	0.10	0.20	
Elasticity of harvested acreage response	0.50	0.50	0.50	0.50	0.50	
Trade elasticity of crops	See Appendix C					
Model Results						
Total land converted (million ha)	1.28	0.85	1.46	0.94	0.94	**1.09**
• Forest land (million ha)	0.43	0.22	0.36	0.40	0.26	**0.33**
• Pasture land (million ha)	0.85	0.63	1.10	0.54	0.68	**0.76**
Brazil land converted (million ha)	0.89	0.59	1.06	0.60	0.55	**0.74**
• Brazil forest land (million ha)	0.30	0.15	0.25	0.26	0.13	**0.22**
• Brazil pasture land (million ha)	0.59	0.44	0.81	0.34	0.42	**0.52**
ILUC carbon intensity (gCO_{2e}/MJ)	56.7	32.3	54.5	48.3	38.3	**46**

* Brazil = 0.80, all other = 0.50

c. Indirect Effects: Land Use Change Effects for Soy Biodiesel

Like the corn ethanol and sugarcane ethanol results presented above, the soy biodiesel land use change results presented in this section were produced using GTAP. The biodiesel estimate presented in this section, however, is very preliminary: it does not appear in the LCFS Lookup Table. Its only use has been the preparation of the diesel fuel compliance scenarios appearing in Chapter VI. When a value sufficiently robust for use in the regulation has been estimated, that value will be published for public comment and proposed for certification.

The results of all soy biodiesel sensitivity runs are summarized in Table IV-13. Starting with the 2001 soy biodiesel production level of 0.005 billion gallons, the GTAP sensitivity analysis considered two production increments: 0.295 billion gallons and 0.695 billion gallons. The model was quite insensitive to variation in production volumes over this range. As a result, all subsequent sensitivity runs on elasticity values were based on a 0.695 billion gallon biodiesel production increase. More complete details are available in Appendix C.

Table IV-13
Sensitivity Analysis Results for Soy Biodiesel

Input variable	Input Variable Ranges		Percent Change in LUC Carbon Intensity
	Low Value	High Value	
Biodiesel production increase (billion gallons)	0.295	0.695	2
Crop Yield Elasticity	0.1	0.5	-40
Elasticity of Harvested Acreage Response	0.5	0.5	Not varied
Elasticity of land transformation	0.1	0.3	26
Elasticity of crop yields w.r.t. area expansion	0.25	0.75	-76
Trade elasticity	1 Std. Dev. Below	1 Std. Dev. Above	-4

For soy biodiesel, the GTAP model used an aggregated oil seeds (soybeans, canola, etc.) category. The average yield for aggregate oilseeds biodiesel used in the model was 2.06 gal/bushel as compared to a yield for soy based biodiesel of 1.47 gal/bushel. To address this difference, land conversion was adjusted by the ratio of 2.06/1.47 outside of the model. The GTAP model also does not account for soy meal co-product credit. As an initial estimate, we assumed a 75 percent co-product credit for soy meal.

In order to select an appropriate central value for the land use change impact of soy biodiesel production, staff narrowed the range of values from the sensitivity analysis by removing the results obtained from the most improbable combinations of input elasticity values. These variables, and the narrowed, 'most reasonable' ranges used are:

- Elasticity of crop yield with respect to area expansion: 0.5 to 0.75;
- Crop yield elasticity: 0.2 to 0.4;
- Elasticity of land transformation: 0.1 to 0.3; and
- Trade elasticity: central case.

The four sensitivity runs that remained following the exclusion of runs outside of the above ranges are shown in Table IV-14. As shown in the rightmost column of Table IV-14, the mean global land conversion value across this narrowed range of runs is 0.44 million hectares. When the total GHG emissions from the conversion of these lands are annualized over a 30-year period, the result is a mean indirect land use change impact of 42 gCO2e/MJ. This analysis is preliminary since the modeling has been conducted for an aggregated oil seeds scenario and then adjusted outside the model for soybeans. Future work includes exploring the use of soybeans only in the model to determine effects attributable directly to soybean based biodiesel.

Table IV-14
GTAP Modeling Results for Soy Biodiesel Land Use Change

Scenario	A	B	C	D	Mean
Economic Inputs					
Biodiesel production increase (bill. gal.)	0.695	0.695	0.695	0.695	
Elasticity of crop yields wrt area expansion	0.50	0.75	0.50	0.50	
Crop yield elasticity	0.25	0.25	0.25	0.25	
Elasticity of land transformation	0.20	0.20	0.30	0.10	
Elasticity of harvested acreage response	0.50	0.50	0.50	0.50	
Trade elasticity of crops	See Appendix C				
Model Results					
Total land converted (million ha)	0.476	0.317	0.536	0.358	**0.441**
• Forest land (million ha)	0.154	0.071	0.144	0.142	**0.137**
• Pasture land (million ha)	0.323	0.246	0.392	0.217	**0.304**
U.S. land converted (million ha)	0.109	0.073	0.129	0.075	**0.100**
• U.S. forest land (million ha)	0.036	0.013	0.030	0.032	**0.030**
• U.S. pasture land (million ha)	0.073	0.059	0.099	0.043	**0.070**
ILUC carbon intensity (gCO_{2e}/MJ)	49	27	51	40	**42**

d. Indirect Effects: Land Use Change Effects for Cellulosic Ethanol

No currently available model is capable of estimating the land-use-change effects of plant-based feedstocks that do not displace agricultural commodities. To assess the land use change effects of cellulosic ethanol produced from such feedstocks, therefore, staff turned to an analysis prepared by Purdue University(57). This analysis evaluated the potential land use change impacts of corn stover, which can be used as feedstock for the production of cellulosic ethanol. Purdue's estimate, however, is very preliminary: it does not appear in the LCFS regulatory Lookup Table. Its only use has been in the preparation of the gasoline compliance scenarios appearing in Chapter VI. When a value sufficiently robust for use in the regulation has been estimated, that value will be published.

Purdue's results indicate that, not only is the use of this feedstock unlikely to generate land use change impacts, it may actually yield benefits in the form of a reduction in the amount of land required for fuel crop cultivation. The Purdue study also analyzed the potential for dedicated energy crops grown on idled or pasture lands to create land use change impacts. Preliminary results indicate that the land use change impacts of these crops are likely to be significantly lower than those for feedstocks that displace food and feed crops.

Some cellulosic feedstocks may be cultivated as crops, but on lands not capable of supporting traditional food and feed crops. In the absence of a model capable of evaluating the land use change impacts of fuels produced from such feedstocks, staff prepared a preliminary analysis of the potential direct land use change impacts of the cellulosic ethanol production requirements contained in the federal Renewable Fuels Standard (RFS2, which is discussed in Chapter II). The RFS2 requires the production of 16 billion gallons of cellulosic ethanol by 2022. Table IV-15 shows the inputs used for this analysis. The feedstock considered—switchgrass—is assumed to yield 250 gallons of ethanol per acre. Given this yield, switchgrass would have to be grown on a total of 25.9 million hectares. For purposes of this analysis, the marginal lands that would be converted to switchgrass cultivation are assumed to emit carbon at a rate that is 25 percent of the Woods Hole rate for U.S. grassland conversion. The Woods Hole emission factor for U.S. grasslands is 110 MgCO2/ha; the resulting factor for the marginal switchgrass land areas, therefore, is 27.5 $MgCO_2$/ha. Based on these assumptions, the land use change carbon intensity value for switchgrass is 18 gCO_2/MJ (see Table IV-16).

This preliminary value for fuels produced from feedstocks grown on marginal lands will be updated when more rigorous modeling results are available. Staff is currently working to integrate the necessary datasets for this analysis into the GTAP model. Once these modifications have been made, staff will prepare and present the modeling results.

Table IV-15
Inputs Used for Preliminary Cellulosic Ethanol Analysis

Parameter	Value
Quantity of cellulosic ethanol	16B gallons
Feedstock	Switchgrass
Ethanol yield	250 gallons/acre[1]
Total land converted in the U. S.	25.9 million ha (approx 64 million acres)
Type of land converted	Grassland or marginal land

[1] The literature contains a wide range of ethanol yields from switchgrass. 250 gallons/acre is the approximate midpoint of this range.(58, 59)

Table IV-16
Preliminary Results for Cellulosic Ethanol

Carbon factor (MgCO2/ha)	Land Use Change (gCO_2e/MJ)
25% of Woods Hole Data for grassland in the U. S.=27.5	18

e. Land Use Impacts from Crude Production in California

This section summarizes work completed by researchers from U.C. Davis and their collaborators(60) on estimating the land use impacts from crude production in California. The scope of the analysis extends to land use change resulting from land disturbance associated with oil operations in California oil fields.

As with biofuels production, producing fossil fuels from a new crude source will likely result in carbon releases from disturbed land. The amount of land disturbed per unit of refined fuel delivered depends on the following characteristics:

- The areal energy density of the deposit (e.g. the amount of primary energy contained per m^2 of surface area);
- The rate at which the primary energy resource (crude) is extracted from the deposit;
- The conversion efficiency between the primary energy resources and refined fuel product; and
- The amount of carbon contained on the land before and after the land disturbance occurs.

Data for California conventional oil production was obtained from the California Department of Oil Gas, and Geothermal Resources (California Department of Conservation 2006(61)). The dataset contains 308 oil fields covering 3×10^9 m^2 (1180 square miles), and a total of 9,775 wells. The cumulative crude oil produced to date is 25.1 billion bbl. Details of the production weighted averages are provided in Table IV-17.

Table IV-17
California Oil Field Characteristics

Number of fields	308
Total area of field (m^2)	3×10^9
Total number of wells	9,775
Average number of wells per field	349
Crude oil produced to date (B bbl)	25.1
Production weighted averages:	
Spacing per well (ha/well)	9.6
Total energy produced to date per well (PJ crude oil/well)	5.94
Energy produced per disturbed area (PJ/ha)	6.74

In consultation with the UC Davis researchers who provided this information, ARB staff determined the most likely cover types, and associated emission factors, for the lands that have been disturbed by oil field development in the State. The results are as follows:

Land use assumptions:

- Drilling is expensive, so oil fields are lightly developed, with tens of acres per well (10-40 sometimes cited), although some will have infill drilling at tighter spacing. Add in roads, and disturbance is still likely to be quite low. We assume 25 percent of field surface area is disturbed[29];
- Disturbance is defined as removal of 100% above-ground biomass carbon and oxidation of 20 percent of soil carbon (scraping of soil at surface for roads, drainage, drill pads);
- Given that nearly all California oil fields are in the southern half of the State, we assume that the land above the California fields is 25 percent chaparral and 75 percent grassland; and
- The carbon emission factors for these land types are assumed to be identical to those used by Searchinger et al. (2008(50)); these factors are shown in Table IV-18.

Table IV-18
Carbon Intensity Assumptions for Oil Production Fields in California

Landscape Type	C in Vegetation (Mg C/ha)	C in Soil (Mg C/ha)	Fraction of Total Disturbed
Chaparral	40	80	0.25
Grassland	10	80	0.75

Preliminary calculations indicate that the GHG emissions associated with oil field land use conversion are in the range of 0.025–1.40 gCO_2e/MJ for California crude production. When adjusted for production-weighted average land use, the GHG emissions from California oil production are 0.061 g CO2e/MJ. Appendix C provides details of the preliminary calculations.

A similar analysis is planned for crude oil from oil sands. Currently, California refineries do not use any crude derived from oil sands. Staff will publish the results of this analysis when it is available.

[29] To estimate the fraction of land in California oil fields that is disturbed, an image analysis program is used to convert the images of three oil fields into binary files (black and white). Black being the vegetation, which is typically much darker than the dirt roads and areas around wells. The percentages without vegetation (white) range from 25-35% for the 3 fields analyzed, with a few images having as low as 10% cleared.

f. Comparison of GTAP Results with Observed Market Behavior

The GTAP is designed to project the specific effects of one carefully defined policy change—namely the increased production of a biofuel. Because it focuses narrowly on a specific set of economic changes, the results obtained from GTAP will not necessarily reflect observed aggregate trends. The model predicts, for example, that the expanded use of domestic corn for the production of ethanol will reduce U.S. corn exports. That prediction appears to be inconsistent with the actual trade data appearing in Appendix C. Those data show that the production of corn, soybeans and wheat in the United States has generally been on the increase over the last decade. Exports meanwhile have remained relatively steady. In the case of corn, production increases have been sufficient to supply the ethanol industry while maintaining export levels. The effects of increased biofuel production on export markets are masked by other phenomena that are not addressed by the GTAP analysis.

The primary influences on exports in recent years have been an increased demand for American agricultural products in rapidly growing economies such as China, a weakening U.S. dollar, and growth in demand for corn ethanol[30]. A significant component of the increased demand in China and other rapidly developing countries is a sharp increase in the consumption of meat and soy products in those countries. This has created a demand for imported soybeans and corn, which are used as livestock feed. This demand has helped to increase prices and has kept U.S. exports steady, despite the rapidly increasing use of corn for the production of ethanol.

The increased demand for corn ethanol, along with strong corn export demand, stimulated a significant increase in corn production over the 2005 through 2007 period (production and planted acreage data are presented in Appendix C). This expansion in corn production coincided with significant decline in soybean production. When U.S. corn acreage is expanded, the crop that is most often displaced is soybeans(50, 62). The resulting shortage of soybeans increased soybean prices, driving production back up in 2007/08.

The overall trend in corn exports, therefore, is the result of many factors, only one of which is the growth in corn ethanol production. Because the observed trend is the net result of several factors, the independent influence of increased ethanol production was masked by competing influences not considered in the GTAP results. It is true, however, that the downward pressure from domestic ethanol production kept exports lower than they would otherwise have been.[31]

---

[31] The LCFS GTAP analysis was designed to isolate the incremental contribution of ethanol production to export levels. Other influences, which can mask the effects of ethanol production, are not included in the model. It is important to keep this fact in mind when evaluating GTAP projections in the context of observed market behavior. GTAP is not predicting the *overall aggregate* market trend—only the incremental contribution of a single factor to that trend. If GTAP projects reduced exports, for example, this should be understood to mean that exports will be lower that what they would have been in the absence of the effect being modeled (increased ethanol production, in this case). It is the difference

The increasing demand for corn ethanol also results in the movement of significant U.S. crop land area out of food and feed production. The USDA's Economic Research Service reports that almost five billion gallons of ethanol were produced in the U.S. in 2006. Production is expected to exceed ten billion gallons by 2009 (Westcott, May 2007). If the targets established in the Energy Independence and Security Act of 2007 are met, production should reach about 15 billion gallons by 2015. Table IV-19 shows the land area requirements for ethanol production levels of this magnitude.

Table IV-19
U.S. Corn Ethanol Production Acreage Requirements

Year	Gallons of Ethanol Produced (Billions)	Acres of Ag. Land Required (Millions)	Percentage of 2008 Planted Corn Acres
2006	5	11.8	13.8%
2009	10	22.6	26.3%
2015	15	31.8	37.0%

[1] Based on ethanol production yields of 2.8 gallons per bushel of Corn(18), and corn yields from USDA Economic Research Service, October 2008. Projected yields for 2009 and 2015 are based on the average yield increase between 2005-06 and 2007-08 (1.3 percent).
[2] Based on a 2007/08 planted corn acreage of 85.9 million acres (USDA Economic Research Service, October 2008)

The implications of diverting cropland to biofuel production on this scale are discussed in section h below ("Food versus Fuel Analysis").

g. Location of Land Use Changes

The GTAP model is designed to respond to changed economic conditions by solving for the most economically efficient new equilibrium point. In response to a 13.25 billion-gallon-per-year increase in the demand for corn ethanol, the model seeks the least-cost source of the corn needed to sustain that demand. Although some additional corn can be obtained through higher yields, the overall demand cannot be met unless the number of acres devoted to corn production can be expanded significantly.

When additional corn acreage is needed, American farmers are most likely to convert soybeans to corn. This is especially true when returns from exports are high, as they have been until very recently. If returns from exports are low, more of the demand for corn would be met through reduced exports, driving a greater proportion of the land use change impact overseas to America's trading partners. Reduced soybean supplies increase soybean prices, stimulating the demand for more land to support soybean production. As with corn, soybean exports have remained high (See Appendix C), causing much of the demand for soybean acreage to met domestically. Soybeans can be grown on land previously devoted to other crops, such as wheat, but, some of the

between predicting an absolute change and a relative change. GTAP projections are incremental and relative.

displaced soybeans, wheat, and other crops must be grown on land that was not previously under cultivation. This is the source of the domestic land use change impact identified by GTAP.

The GTAP brings new land into agricultural production from forest and grassland areas. It isn't specific about exactly where that land will come from. Some could come from the Conservation Reserve Program (CRP). Most CRP lands are in the arid far west and could support soybean production but not corn. Although the penalties for breaking CRP contracts are steep enough to prevent CRP lands from being used before their contracts expire, contracts are currently expiring on two million acres due to provisions contained in the recent Farm Bill. The USDA has the authority to make additional CRP lands available. If sufficient CRP land is not available to indirectly support an expansion of corn acreage, a large supply of non-CRP pasture land that was formerly in crops could be brought back into production. It is the availability of this non-CRP former crop land that is behind the GTAP's projection that about 40 percent of the land converted worldwide in response to the increased demand for corn ethanol biofuel will occur in the U.S.

The GTAP modelers assumed that no CRP land would be converted in response to increased biofuel demand. Although some CRP land has been released for cultivation, an abundance of previously farmed pasture land is also available. These pasture lands are generally more productive than the lands released from the CRP system. Before it becomes economical to convert the least productive domestic land areas, land use change tended to shift overseas.

The staff is continuing to analyze the effects of including CRP land in the land pool used by the GTAP model.

h. Food Versus Fuel Analysis

The LCFS, together with biofuel production mandates in the U.S. and Europe, will result in the diversion of agricultural land from food production to biofuel feedstock production. This diversion of agricultural land to biofuel production will exert an upward pressure on food commodity prices, and potentially lead to food shortages, increasing food price volatility, and inability of the world's poorest people to purchase adequate quantities of food (63, 64). As both food prices and corn ethanol production levels rose during 2007 and the first part of 2008, warnings about a possible linkage between the two trends began to surface(65). Controversies over the trade-offs between food and fuel crops are likely to intensify as crop-based biofuel production increases over the next decade. In this section, ARB staff discusses various food-versus-fuel issues associated with the production of corn and sugarcane ethanol—the biofuels that are expected to dominate the alternative fuels market over the next five years.

The primary benefits of increased production and consumption of biofuel are thought to be twofold. The first—an increase in energy security—is the rationale for the Energy Independence and Security Act (EISA). In 2007, the U.S. imported roughly two-thirds of its oil with over 50% of the imports coming from OPEC countries (EIA 2009). This dependence on foreign oil leaves the U.S. vulnerable to supply disruptions and price shocks. Increasing the domestic production of corn ethanol will diversify our fuel supply and potentially leave us less vulnerable to decisions made by foreign countries and oil producers.

The second perceived benefit of increased reliance on biofuels—a reduction in GHG emissions—is the rationale behind the LCFS. On an energy basis, direct GHG emissions[32] from the production and use of corn and sugarcane ethanol are less than the comparable emissions from gasoline. When land use change emissions are considered, however, the emission-reduction benefit from corn and sugarcane ethanol is diminished.

Some of the costs and benefits associated with a 50 million gallon per year corn ethanol plant operating in California are summarized below (See Appendix C for a description of how the values appearing in this summary were derived). Such a plant would:

- Provide enough fuel for approximately 80,000 vehicles capable of operating on E-85;

- Displace about 34 million gallons of petroleum fuel;

- Reduce direct GHG emissions by about 0.19 million metric tons per year;

- Require almost 18 million bushels of corn per year;

- Require about 110,000 acres of U.S. farmland to produce the feedstock;

- Result in about 36,000 acres of land conversion, 14,000 acres of which would be in the U.S.; and

- Result in the release of 3.6 million metric tons of greenhouse gases due to land conversions; and

- Result in a net greenhouse gas emission benefit after 19 years of production.

In addition to the costs listed above, the conversion of agricultural land to the production of biofuel feedstocks has the potential to increase the price for food, increase food price volatility, and increased pressure on water supplies. The production capacity of the ethanol plants currently operating and under construction in the U.S. is approximately 13 billion gallons per year (BGPY)(54). About 4.6 billion bushels of corn—more than 30 percent of the annual U.S. corn crop—is needed to support this level of production.

[32] Direct and indirect GHG emissions, as well as the concept of indirect land use change, are discussed in detail in preceding sections of this Chapter

Diverting this much of the American corn harvest to ethanol production is likely to exert upward pressure on food prices(66).

Historically, the price of corn has been relatively stable varying from about $2.00 to $2.50 per bushel between 2000 and 2006. Prices in 2008, however, spiked at over $5 per bushel and are currently near $4 per bushel(55). The recent sharp increase in corn prices was not caused solely by the conversion of acreage devoted to food and feed production to biofuel crops. The cost of energy appears to have been the largest contributor (65, 67). The demand for biofuel feedstocks may, however, be overwhelming a food supply system that was already overextended by weather-induced production shortfalls and surging demand from a worldwide population that is both increasing in size and affluence. Increased meat and dairy consumption by newly affluent populations places additional demands on soy and corn—feed crops that are also used for direct human consumption and biofuel production(64). Moreover, the increased production of biofuels may more firmly link prices of biofuel feedstocks with petroleum prices, thereby leading to increased price volatility for food(63): as petroleum fuel prices increases, biofuels become more profitable which, in turn, allows producers to raise their feedstock prices as they increase production levels. Because those with the lowest incomes must devote a large percentage of those incomes to food, they are less able to adjust to changing food prices in the short term.

An important factor in the food versus fuel debate that has received relatively little attention until recently is the impact of expanded biofuel production on water supply and water quality. The shift in U.S. agricultural production toward corn, the conversion of land to agriculture (indirect land use change), and the growth in the number of bio-refineries will place additional demands on already overburdened water supplies. The water use impact of devoting a larger proportion of available agricultural land to corn production depends on the crop that is being replaced as well as its geographical location. Of more concern, however, is the expansion of agriculture in dry areas like the western U.S.: altered cropping patterns on relatively moist agricultural lands will usually have less of an impact than expanding irrigated production in relatively arid areas.

Bio-refineries can also place a strain on local water supplies. A refinery that produces 100 million gallons of corn ethanol uses as much water as a town of 5,000. More intensely managing land to improve yields may also exacerbate water quality problems: soil erosion along with fertilizer and pesticide runoff can increase as crop management intensifies(68, 69). Bringing non-agricultural lands into production can also increase erosion and runoff. Conservation Reserve Program (CRP) lands are of special concern: the CRP was created, in part, to protect environmentally sensitive or highly erodible acreage.

4. Ongoing Analyses

a. Additional Analyses of Indirect Effects of Other Feedstocks

As discussed above, the results of the analyses for biodiesel and cellulosic ethanol are preliminary. Additional data must be added to the GTAP model before it can be used to estimate the land use change impacts of these fuels.

Staff is currently working with CEC, Purdue researchers, the U.S. EPA and others in determining appropriate inputs, values, etc. for soybean based biodiesel and cellulosic ethanol from non-food crops and waste. Results will be published when the analyses are completed.

Staff is also continuing to analyze and refine the corn ethanol land use change results. Work is underway in the following areas:

- The possible inclusion of Conservation Reserve Program Land in the analysis;
- The use of improved emission factors, as they become available;
- The evaluation and possible use of data and analyses provided by stakeholders; and
- Characterizing in greater detail of the land use types that are subject to conversion by the GTAP model (forest, grassland, idle and fallow croplands, etc.).

The results of these analyses will be published when they are completed.

b. Comparison to U.S. EPA's Approach

The U.S. EPA is evaluating the potential indirect land use impacts of the Federal Renewable Fuel Standard regulation (RFS). The RFS establishes volumetric requirements for various categories of biofuels (the RFS is discussed in Chapter II of this Report). Its primary goal is increased energy independence rather that reduced fuel carbon intensity. Despite these differences, the economic forces driving indirect land use change are the same in the RFS and the LCFS. For that reason, the ARB is working closely with the U.S. EPA to assure that the approaches taken in the two analyses are as consistent and transparent as possible.

D. Uncertainties in the Analysis

Chapter IV and Appendix C describe a number of modeling inputs that affect the fuel carbon intensity estimates. The lifecycle analysis process used to determine the contribution of fuel production, distribution, and use is fairly mature: direct carbon intensity values calculated via lifecycle analysis are relatively non-controversial. The land use change analysis, however, has generated large numbers of comments on all sides of the issue. Some stakeholders argue that the land use change carbon intensity value for crop based biofuels should be near 0 gCO_2e/MJ. Others argue that ARB should err on the side of caution and set the land use change carbon intensity value at 100 or more gCO_2e/MJ.

In this section, we briefly summarize those inputs that result in the greatest uncertainty and discuss decisions made by the ARB with respect to those inputs. We organize this discussion into issues associated with estimating land conversion, applying emission factors, accounting for time, and other factors. This list is meant to summarize some of the more significant issues rather than to be comprehensive.

The uncertainties associated with the land conversion estimates are largely the result of the following model inputs:

- Elasticity values used in the economic modeling. As discussed in the results section, model output is moderately to highly sensitive to the crop yield elasticity; elasticity of land transformation across cropland, pasture, and forest land; and elasticity of crop yields with respect to area expansion (relative productivity of marginal land). In calculating a value for land conversion, ARB staff and GTAP modelers have determined what we believe to be the most reasonable ranges for these elasticity values. These ranges are derived from appropriate research results, unless no such results are available. In the absence of research findings, the best professional judgment of experts has been relied upon. In particular, model outputs are highly sensitive to the value assigned to the relative productivity of marginal land. The land conversion predicted by the model is inversely proportional to the relative productivity assumed for marginal land. A range from 0.25 to 0.75 was originally assigned to this elasticity (e.g. marginal land is 25 to 75 percent as productive as land currently used for agriculture). Based on feedback from stakeholders, ARB staff and GTAP modelers decided that 0.50 to 0.75 was a more appropriate range for this elasticity value which resulted in a lower estimate for land conversion. We will continue to analyze available evidence for this key input parameter.

- DGGS and co-product credit. A recent report by Dr. Michael Wang et al.(70) (2008) of Argonne National Laboratory arrived at a distiller's grain co-product value that is higher than the value used in the LCFS life cycle emissions model. This issue is discussed in more detail in Appendix C. Although Dr. Wang's analysis was based on a limited data set, the results were generalized to the entire livestock industry. For the reasons presented in Appendix C, staff believes that it may not yet be appropriate to generalize from Dr. Wang's limited findings. In fact, DDGS appears to face significant barriers to widespread adoption as a replacement for corn and soybean meal. For this reason, staff feels that providing a co-product credit equating 1lb of DDGS to 1lb of feed corn is reasonable.

- Increases in crop yield with time. GTAP uses the 2001 world economy as a baseline and does not account for changes that have occurred over the past eight years. The change that has the most significant effect on the land conversion estimate is the increase in crop yields since 2001. An increase in crop yields will lead to a corresponding decrease in land conversion. In response to this stakeholder concern, ARB staff and GTAP modelers have adjusted the land conversion estimate to account for the observed increase in crop yields. This adjustment was made to the model results rather than within the GTAP itself. Some stakeholders have responded to this adjustment by claiming that it is based on faulty logic. ARB staff and GTAP modelers do not agree with this comment. A more thorough discussion of our response is given in Appendix C.

- Inclusion of Conservation Reserve Program land. The GTAP model does not include Conservation Reserve Program land in the pool of available land in the U.S. for agricultural expansion. ARB staff and GTAP modelers are updating GTAP to include Conservation Reserve Program land, as appropriate. We will then analyze the effect that this change has on the estimate for amount and location of land converted within the U.S.

An additional source of uncertainty is the application of emission factors to land use change data. These uncertainties are largely the result of the following assumptions:

- The percentage of the above ground carbon that is released to the atmosphere upon land conversion. Stakeholders argue that when forests are converted to cropland, some of the above ground mass will be converted to wood products, paper, and other consumer goods. The carbon in these items will continue to be stored while these products are used, and, in many cases, after they have been deposited in landfills. ARB staff recognizes the validity of this argument and is continuing to analyze the issue to determine the most appropriate percentage of above ground carbon that is released to the atmosphere. Our current modeling assumes 90 percent of the above ground carbon is released to the atmosphere following land conversion. ARB staff also notes that decay of biomass in landfills will more likely lead to release of methane (a more potent GHG) rather than carbon dioxide. This would have to be considered if a non-trivial percentage of biomass from converted lands is placed in landfills.

- The percentage of below ground carbon that is released to the atmosphere upon land conversion. A literature review conducted by Murty et. al.(52) of scientific studies of land conversion reported that the percentage of soil carbon released upon land conversion varied from 0 to 72 percent with an average reported loss of approximately 30 percent. When these values were corrected for changes in bulk density of the soil, the average loss was 22 percent. Another review conducted by Guo and Gifford(51) reported the average loss of carbon in soils for forests converted to crops was 42 percent and from pasture converted to crops was 59 percent. Lower losses were reported for forests and pastures converted to plantations (13 percent and 10 percent respectively). ARB staff and GTAP modelers assume that 25 percent of the carbon stored in the soil is released when land is cultivated. We believe this value is a reasonable compromise given the variability in data.

The uncertainties associated with time accounting are largely the result of:

- The choice of time accounting method used. The Fuel Warming Potential method yields larger values for land use change carbon intensity compared to the Annualized method. ARB staff has chosen the annualized method but will continue to analyze the FWP method.

- The choice of project horizon. A shorter project horizon yields larger land use change carbon intensity values. ARB staff has chosen a 30 year project horizon for crop based biofuel but is considering a shorter 20 year horizon.

- The choice of impact horizon. A shorter impact horizon yields larger land use change carbon intensity values for the FWP method. The duration of the impact horizon is has no effect on the annualization method.

- The amount of land reversion to include and the time period for land reversion. Including land reversion yields significantly lower land use change carbon intensity values for the annualized method as well as for the FWP method at impact horizons long enough to include land reversion.

- The time profile assumed for above and below ground emissions. The assumed length of time over which above and below ground emissions occur affects the land use change carbon intensity values for the FWP method but not the annualized method.

These topics are discussed in more detail in both Chapter IV and in Appendix C. In Appendix C, we present scenarios that explore these issues and show the effect of changing assumptions on the land use change carbon intensity value for corn ethanol. For the annualized method we present land use change carbon intensity values ranging from 22 to 43 gCO_2e/MJ, for the FWP method (30 year impact horizon) we present values ranging from 44 to 55 gCO_2e/MJ and for the FWP method (50 year impact horizon) we present values ranging from 34 to 48 gCO_2e/MJ.

Other issues that affect the uncertainty in the carbon intensity value are:

- Reduced enteric fermentation in livestock fed with distillers grains. Stakeholders have commented that a recent report from Argonne National Laboratory indicates that use of distillers grains as livestock feed reduces enteric fermentation. ARB staff has not included an emissions adjustment for reduced enteric fermentation but will continue to analyze relevant scientific studies and make appropriate adjustments in the future if deemed necessary.

- GTAP modeling neglects other possible effects of land conversion such as changes in Earth's albedo. The albedo is the extent to which an object diffusely reflects light from the sun. Converting from one land use type to another may affect the albedo. ARB staff has not conducted an analysis of this effect.

- The land use change analysis neglects the potential for converting grassland into forest. One strategy mentioned for reducing the atmospheric concentration of carbon dioxide is to convert current grasslands into forest which results in sequestration of carbon dioxide. This land conversion is often mentioned as a method for GHG emitters to offset emissions under cap and trade emissions programs. The conversion of grasslands to agriculture removes this land from the potential pool of land that could be converted to forest. Therefore, it could be considered as a "lost opportunity" or "opportunity cost" and be included in the land use change carbon intensity calculation(71).

- Uncertainties associated with the nitrogen cycle. Stakeholders have commented that significant uncertainty exists in the estimates for N_2O release used in lifecycle analysis models such as GREET. The non-trivial impact of N_2O emissions on the direct carbon intensity calculated by GREET and the large uncertainty in actual measurements of N_2O emissions suggests we need more research in this area. ARB staff will continue to analyze relevant scientific studies and make adjustments to the CA-GREET model if necessary.

The above discussion points out the large number of factors that significantly affect the carbon intensity value for a biofuel. As part of the LCFS, ARB has committed to determining the total direct and indirect emissions associated with production, distribution, and use of all fuels through conducting complete lifecycle analyses based on the best available science. Although one may argue that there is no scientific consensus as to the precise magnitude of land use change emissions and that the methodologies to estimate these emissions are still being developed, scientists generally agree that the impact is real and significant. Our analyses support this conclusion. We believe that we have conducted a fair and balanced process for determining reasonable values for land use change carbon intensity and we will continue to investigate many of the issues presented above through discussion with stakeholders and analysis of current and new scientific data.

E. Proposed Lookup Tables

The results of ARB's carbon intensity analyses to date are shown in Tables IV-20 and IV-21. These are the same values reported in Tables IV-1 and IV-2, without the vehicle energy efficiency ratio adjustments. As such, these are the combined direct and indirect carbon intensity values that ARB proposes for inclusion in the LCFS regulation. These tables represent the proposed Lookup Tables for the default carbon intensities. Note that in the calculations of credits and deficits, these values would adjusted by the Energy Economy Ratios.

Table IV-20
Lookup Table for Carbon Intensity Values
for Gasoline and Fuels that Substitute for Gasoline

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
		Direct Emissions	Land Use or Other Effect	Total
Gasoline	CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies	95.86	0	95.86
	CaRFG-CARBOB and a blend of 100% average Midwestern corn ethanol to meet a 3.5% oxygen content by weight blend (approximately 10% ethanol)	96.09	---	96.09
	CaRFG-CARBOB and a blend of an 80% Midwestern average corn ethanol and 20% California corn ethanol (dry mill, wet DGS) to meet a 3.5% oxygen content by weight blend (approximately 10% ethanol)	95.85	---	95.85
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; 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	47.40	30	77.40
Ethanol from Sugarcane	Brazilian sugarcane using average production processes	27.40	46	73.40
Compressed Natural Gas	California NG via pipeline; compressed in California	67.70	0	67.70
	North American NG delivered via pipeline; compressed in California	68.00	0	68.00
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in California	11.26	0	11.26
Electricity	California average electricity mix	124.10	0	124.10
	California marginal electricity mix of natural gas and renewable energy sources	104.70	0	104.70
Hydrogen	Compressed H_2 from central reforming of NG	142.20	0	142.20
	Liquid H_2 from central reforming of NG	133.00	0	133.00
	Compressed H_2 from on-site reforming of NG	98.30	0	98.30
	SB 1505 Scenario; Compressed H_2 from on-site reforming with renewable feedstocks	76.10	0	76.10

Table IV-21
Lookup Table for Carbon Intensity Values
for Diesel and Fuels that Substitute for Diesel

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ) Direct Emissions	Land Use or Other Effect	Total
Diesel	ULSD – based on the average crude oil delivered to California refineries and average California refinery efficiencies	94.71	0	94.71
Compressed Natural Gas	California NG via pipeline; compressed in California	67.70	0	75.22
	North American NG delivered via pipeline; compressed in California	68.00	0	75.56
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in California	11.26	0	11.26
Electricity	California average electricity mix	124.10	0	124.10
	California marginal electricity mix of natural gas and renewable energy sources	104.70	0	104.70
Hydrogen	Compressed H_2 from central reforming of NG	142.20	0	142.20
	Liquid H_2 from central reforming of NG	133.00	0	133.00
	Compressed H_2 from on-site reforming of NG	98.30	0	98.30
	SB 1505 Scenario; Compressed H_2 from on-site reforming with renewable feedstocks	76.10	0	76.10

This Page Left Intentionally Blank

V. Summary of the Proposed Regulation

In this Chapter, we provide a plain English discussion of the key requirements of the proposed LCFS regulation. This Chapter begins with a general overview of the regulation and the approach taken in developing the requirements in the proposal. The remainder of the Chapter follows the structure of the proposed regulation and provides an explanation of each major requirement of the proposal. This Chapter is intended to satisfy the requirements of Government Code section 11346.2, which requires that a non-controlling "plain English" summary of the regulation be made available to the public.

A. Overview of the Proposed Regulation

The proposed regulatory action would reduce greenhouse gases (GHG) emissions by reducing the carbon intensity of transportation fuels used in California by an average of 10 percent by the year 2020. Carbon intensity is a measure of the direct and other GHG emissions associated with each of the steps in the full fuel-cycle of a transportation fuel (also referred to as the "well-to-wheels" for fossil fuels, or "seed or field-to-wheels" for biofuels). 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 step requires. Thus, carbon intensity is typically expressed in terms of grams of CO_2 equivalent per mega-Joule (gCO_2e/MJ).

The LCFS achieves a 10 percent reduction in average carbon intensity by starting specified providers of transportation fuels (referred to as "regulated parties") at an initial level and incrementally lowering the allowable carbon intensity for transportation fuels used in California in each subsequent year. A regulated party's overall carbon intensity for its pool of transportation fuels would then need to meet each year's specified carbon intensity level. Regulated parties can meet these annual carbon intensity levels with any combination of fuels they produce or supply and with LCFS credits acquired in previous years or from other regulated parties.

As indicated, the LCFS is based on a system whereby credits, which are generated from fuels with lower carbon intensity than the annual carbon intensity standards, balance the deficits that result from the sale of fuels in California that have higher carbon intensity than the annual carbon intensity standards. A regulated party would meet the carbon intensity requirements if the amount of credits at the end of the year is equal to, or greater, than the deficits. Credits and deficits are determined based on the amount of fuel sold, the carbon intensity of the fuel, and the efficiency by which a vehicle converts the fuel into useable energy. Credits may be retained and traded by regulated parties within the LCFS market to meet their obligations.

Under the LCFS, a regulated party's compliance with the annual carbon intensity requirements is based on end-of-year credit/deficit balancing for each year between

2011 and 2020 and beyond. Technically, the LCFS goes into effect in 2010, but the first year of the program is intended as a “break in” reporting year, which will allow both the regulated parties and ARB program staff to acclimate to the LCFS rule’s intricacies and to identify any programmatic changes that may be needed as the program is implemented.

A key function of the LCFS is to incentivize the use of lower-carbon intensity alternative fuels (i.e., fuels that are not conventional gasoline or diesel fuel). Alternative fuels include, but are not limited to, biofuels such as ethanol, biodiesel, and renewable diesel fuel; compressed or liquefied natural gas, both from petroleum or from biomass sources; hydrogen; and electricity. Each of these fuels will have carbon intensity values associated with a lifecycle analysis that will ultimately include other effects, including effects from land use changes, if any.

The proposal contains carbon intensity values for a variety of fuel pathways that have been analyzed by ARB staff. These specific carbon intensity values will be published in a Lookup Table, which will make it easier for fuel producers and importers to identify the appropriate carbon intensity value for the fuel pathway that corresponds with the pathway for their respective fuels. The Lookup Table contained in the proposal is intended to be a “living document,” representing the starting point for carbon intensity values and specific fuel pathways. However, the proposal contains provisions for regulated parties to generate modified or additional fuel pathways with associated carbon intensity values; these provisions are intended to accommodate innovations in producing lower carbon intensity fuels in the future. As these modified or additional fuel pathways are approved by the Executive Officer in a public process, the modified or additional approved carbon intensity values will become incorporated into the Lookup Table.

B. Applicability of the Standard

In order to meet the 10 percent reduction target and additional climate stabilization beyond 2020, California must rely on a diverse portfolio of fuels, such as a mixture of advanced low-carbon fuels, low-carbon blendstocks, and vehicle technologies. The scope of the standard is designed to capture the diverse fuel portfolio available today and in the near future, while offering a fuel-neutral platform in which alternative fuels can be incentivized without choosing winners or losers. Therefore, staff proposes the LCFS apply, either on a compulsory or opt-in basis as set forth in the proposal, to most types of fuels used for transportation in California, including:

- California reformulated gasoline;
- California 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.

As noted below, the proposal contains a few fuel- and application-specific exemptions.

1. Credit Generation Opt-In Provision for Specific Alternative Fuels

The proposed regulation includes an opt-in provision for certain alternative fuels that have full fuel-cycle, carbon intensities that inherently meet the proposed compliance requirements through 2020. These fuels are electricity, hydrogen and hydrogen blends, fossil CNG derived from North American sources, biogas CNG, and biogas LNG. Regulated parties for these fuels are required to meet the LCFS requirements (e.g., reporting, credit balancing) only if they elect to generate credits based on these fuels as provided under the proposal. Generally, parties that opt into the LCFS program will be those parties that expect to generate LCFS credits under the regulation. By opting into the program, a person becomes a regulated party under the LCFS regulation and is required to meet the LCFS reporting obligations and requirements. The provisions for opting into the LCFS are set forth in the proposal.

2. Exemption for Specific Fuels and Applications

The proposal exempts any alternative fuel that is not biomass-based or renewable biomass-based and for which the aggregated volume by all parties for that fuel is less than 420 million mega-Joules per year (3.6 million gasoline gallon equivalent per year). This is intended to exempt research fuels entering the market or very low volume niche fuels. The exemption is intended to allow alternative fuel providers, particularly small-volume producers whose fuels have inherently low carbon intensities, adequate lead-time to develop the technologies necessary to make their fuels viable for future transportation applications.

Not all alternative fuels, however, qualify for the low volume exemption. Biomass-based fuels, such as denatured fuel ethanol and biomass-based diesel, and fuel blends containing biomass-based fuels, do not qualify for the exemption regardless of the quantity produced due to the potential land-use impacts and other global sustainability and economic considerations of biofuels. Persons claiming this exemption would need to demonstrate to the Executive Officer’s satisfaction that they meet the requirements for this exemption.

It should be noted that this exemption dates back to the beginnings of the LCFS rule development, but it currently may be of limited utility. It was originally intended as a “catch-all” provision that would provide incentives for low volume, low carbon-intensity fuels, as well as those fuels for which an exemption was justified on other bases. However, the proposal as currently written specifically addresses many of the original reasons underlying this exemption. For example, hydrogen was originally intended to be subject to this exemption, but that fuel is now covered by the voluntary opt-in provision noted above. Because the exemptions in the proposal are now explicit for a number of alternative fuels and specific fuel applications, this general low-volume exemption has been made moot for the vast majority of its originally intended uses. Thus, staff may propose amendments to this exemption as a 15-day change to eliminate or more narrowly focus the exemption.

In addition to the low volume exemption noted above, the proposal does not apply to regulated parties providing liquefied petroleum gas (LPG or propane). Staff is proposing to exempt propane because it neither plays a significant role as a transportation fuel in the current market, nor is it anticipated to be a significant contribution to the transportation pool in the 2010 to 2020 timeframe.(72)[33]

There is also an exemption for specific applications of transportation fuels, including fuels used in aircraft, racing vehicles, interstate locomotives, ocean-going vessels, and military tactical vehicles. However, it is important to note that this exemption does not apply to recreational watercraft and to *intra*state locomotives and commercial harborcraft, for which the diesel fuel is already subject to the requirements in 17 CCR § 93117 (i.e., required to use on-road California diesel). Because of this, the fuel sold or offered for sale for use in recreational watercraft (subject to existing ARB on-road fuels regulations) and the diesel fuel sold or offered for sale for use in intrastate locomotives and commercial harborcraft subject to 17 CCR § 93117 would be treated the same as any other transportation fuel subject to the LCFS.

C. Definitions

There are numerous definitions specified in order to facilitate implementation of the LCFS program, including key definitions such as:

- "Transportation fuel," which means any fuel used or intended for use as a motor vehicle fuel or for transportation purposes in a nonvehicular source.
- "Blendstock," which 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 CA-GREET. A blendstock that is used directly as a transportation fuel in a vehicle is considered a finished fuel.

- "Carbon intensity," which means the amount of lifecycle greenhouse gas emissions, per unit of energy of fuel delivered, expressed in grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ).

[33] Western Propane Gas Association, citing ICF International's memorandum on Assessment of Propane Engine Fuel Sales in California, January 8, 2009 "(… analysis indicates that propane used in this market [engine fuels in California] has been relatively flat for the last several years. Modest growth in the forklift market, which is driven by economic growth, has been offset by declines in propane used in on-road vehicles. There has been very few new propane vehicles added in California during this period due to the lack of suitable OEM propane vehicles and certified propane vehicle conversion kits.").

- “Credits” and “deficits,” which are the measures used for determining a regulated party’s compliance with average carbon intensity requirements in the proposal. Credits and deficits are denominated in units of metric tons of carbon dioxide equivalent and are calculated in accordance with the specified procedures.
- “Finished fuel,” which means a fuel that is used directly in a vehicle for transportation purposes without requiring additional chemical or physical processing.
- “Lifecycle greenhouse gas emissions,” which 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.
- “Regulated party,” which means a person who must meet the average carbon intensity requirements specified in the proposal.

D. Average Carbon Intensity Requirements

1. Compliance Schedule

As noted, the LCFS achieves the goals of Executive Order S-01-07 by incrementally reducing the allowable carbon intensity of transportation fuel used in California. The LCFS does not limit the carbon intensity of individual batches or types of fuels, but it does require regulated parties to comply with annual, average carbon-intensity levels for the total amount of fuel they provide in California. The allowable carbon intensity of transportation fuels decreases each year, starting in 2011, until the carbon intensities of gasoline and diesel transportation fuels in 2020 and beyond are each reduced by and average of 10 percent relative to 2010.

Under the proposal, the carbon intensity for alternative fuels that substitute for gasoline or diesel fuel (e.g., biofuels, natural gas, hydrogen, electricity) would be judged against either the gasoline or diesel carbon intensity requirements, depending on whether the alternative fuel is used for light- and medium-duty vehicles or for heavy-duty vehicles, as specified in the regulation. In general, alternative fuels that substitute for gasoline and are used in light-duty or medium-duty applications will be compared to the gasoline standard. Similarly, alternative fuels that substitute for diesel fuel and are used in light-duty, medium-duty, or heavy-duty vehicles, locomotives, and off-road vehicles are compared to the diesel standard.

It is important to note that light-duty use of diesel fuel is treated similarly to heavy-duty use of the fuel and a regulated party references the diesel standard for all applications of diesel. A separate standard for diesel would minimize fuel shuffling to diesel as a method of compliance with the LCFS and the health effects associated with dieselization, and would incentivize improvements in petroleum-based conventional fuels.

In each year under the LCFS, the carbon intensity of each fuel is compared to the carbon intensity requirement for that year. Fuels that have carbon intensity levels below the requirement generate credits. Fuels with carbon intensity levels above the requirement create deficits. To comply with the LCFS for a given year, a regulated party must show that the total amount of credits equal or exceed the deficits incurred. Excess credits can be retained or sold to other regulated parties.

Staff expects that more stringent standards will be set in the future for the years past 2020 in order to achieve additional GHG emission reductions to help meet 2050 GHG emission reduction goals.

As noted, the proposed compliance schedules for gasoline and diesel fuel follow similar carbon intensity reduction percentages from 2011 through 2020. The schedules are back-loaded or technology-forcing, with the majority of reductions occurring after 2015. Table 1 shows the carbon intensity values of gasoline and gasoline-substitutes, and diesel and diesel-substitutes from 2011 to 2020. The back-loaded compliance schedules take into consideration the availability of biofuels through the Energy Independence and Security Act, the availability of advanced electric vehicles such as plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs), and the availability of flex-fuel vehicles (FFVs) during the implementation of the LCFS. Additional information about the scenarios used to determine the compliance schedules can be found in Chapter VI.

Table V-1
LCFS Compliance Schedules

Year	**CI for Gasoline and Fuels Substituting for Gasoline[1] (g/MJ)**	**Gasoline and Fuels Substituting for Gasoline % Reduction**	**CI for Diesel and Fuels Substituting for Diesel (g/MJ)**	**Diesel and Fuels Substituting for Diesel % Reduction**
2010	Reporting Only		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	86.27	10.0%	85.24	10.0%

The carbon intensity reductions shown in Table 2 are displayed graphically in Figure 1 and Figure 2.

Figure 1

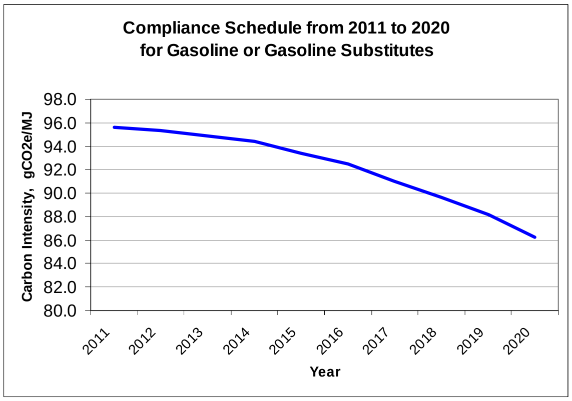
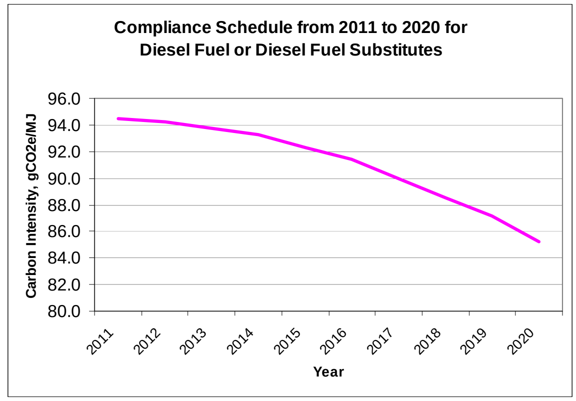


Figure 2



2. Baseline Year and Baseline Carbon Intensity

The proposed regulation considers 2010 as the baseline year against which a 10 percent reduction in GHG emissions is mandated by 2020.(2)[34] Staff believes it is important to allow regulated parties the opportunity in the first year to get acclimated with the LCFS requirements and to allow LCFS design improvements to be identified. Therefore, under the proposal, 2010 is the first year of implementation, which imposes only reporting requirements on regulated parties.

The baseline carbon intensities for gasoline and diesel were calculated using CA-GREET version 1.8b. The gasoline carbon intensity was determined using 10 percent by volume corn ethanol and has a carbon intensity of 95.85 gCO_2e/MJ. The carbon intensity of diesel in 2010 was determined to be 94.71 gCO_2e/MJ. Details for both gasoline and diesel carbon intensity calculations can be found in Chapter IV.

In 2006, California reformulated gasoline (CaRFG3) contained an average of six percent ethanol by volume. However, as a result of the implementation of the Federal Energy Independence and Security Act of 2007 and compliance with the amended CARFG3 regulations, the amount of ethanol in CaRFG is expected to increase to about 10 percent by volume. Therefore, the baseline carbon intensity for gasoline is determined using 10 percent by volume corn ethanol to reflect the expected changes in gasoline formulations between 2006 and 2010. Furthermore, for the purpose of baseline calculations, staff projects that in 2010 the following mix of corn ethanol will be

[34] The Executive Order S-01-07 was issued in January 2007, therefore the objective is to achieve an overall 10 percent reduction in the carbon intensity of fuels by 2020 from 2006. The proposed regulation achieves this objective because the carbon intensity of the 2010 baseline is essentially equivalent to the baseline in 2006.

available for blending in California: 80 percent produced in the Midwest[35] and 20 percent produced in California.[36]

Staff does not expect any significant penetration of alternative fuels that would affect the carbon intensity of the baseline diesel fuel between 2006 and 2010. Therefore, the diesel baseline carbon intensity is determined using California ultra-low sulfur diesel fuel (ULSD).

E. Applicable Standards for Alternative Fuels

As noted, a regulated party that provides an alternative fuel such as ethanol, biomass-based diesel, electricity, and hydrogen and hydrogen blends will use either the gasoline or diesel standard, depending on how the fuel is used in a vehicle. Fuels using the gasoline standard are referred to in the regulation as gasoline-substitutes and those using the diesel standard are referred to as diesel-substitutes.

1. Single-Fuel Vehicles

Single fuel vehicle means a vehicle that uses a single external source of fuel for its operation. Generally in such vehicles, light-duty or medium-duty applications of an alternative fuel will use the gasoline standard. All other applications will use the diesel standard.

While the application of an alternative fuel is an important factor in determining which standard to use, another important factor is whether gasoline or diesel is displaced by the use of the alternative fuel. Thus, an exception to the general rule above applies to biomass-based diesel fuels. The diesel fuel standard is to be used for all applications of the biomass-based diesel fuel that are regulated under the LCFS, since typically biomass-based diesel displaces ULSD.

2. Multi-Fuel Vehicles

A multi-fuel vehicle use two or more fuels for its operation. For alternative fuels used in such vehicles, the gasoline average carbon-intensity requirement is used if one of the fuels used by the vehicle is gasoline. Similarly, the diesel average carbon-intensity requirement is used if one of the fuels used by the vehicle is diesel fuel.

In the case of multi-fuel vehicles using alternative fuels only (i.e., no gasoline or diesel fuel), provisions similar to single fuel vehicles would apply. For light-duty or medium-duty applications, the gasoline average carbon-intensity requirement is used for all alternative fuels. For all other applications, the diesel average carbon-intensity requirement is used.

---

[35] In the Midwest, 80 percent corn ethanol is produced via dry milling and 20 percent via wet milling, dry DGS process.

[36] In California, all corn ethanol is produced via dry milling, wet DGS process.

F. Requirements for Regulated Parties

1. Using "Regulated Party" instead of "Point of Regulation"

In developing the regulatory language, staff believes it is important to recognize the potential enforcement differences between the LCFS and current standards for liquid fuels such as CaRFG3 and ULSD. The CaRFG3 regulation considers the point of regulation to be the point at which the fuel producers release finished fuel CaRFG3 throughout the distribution system. Compliance can be determined systematically through fuel sampling and testing.

Unlike the CaRFG3 and ULSD rules, the proposed LCFS regulation uses calculated lifecycle fuel carbon intensity. Carbon intensity is based on properties inferred from a fuel's production; it cannot be abstracted directly from the fuel or measured by analytical instruments. Therefore, in addition to the ideal attributes above, the LCFS point of compliance needs to take into consideration which entity is in the best position to document that a fuel's appropriate carbon intensity values have been used. Based on this and other considerations, staff determined that identifying the "regulated party" would better serve the LCFS program than identifying the "point of regulation."

2. Identification of Regulated Parties

The proposed regulation designates which entities in the fuel supply chains are obligated to demonstrate compliance with the LCFS. These entities are referred to as "regulated parties" and are responsible for the fuel and for reporting fuel information to the Board. In general, the regulation places compliance obligations initially on regulated parties that are upstream entities (i.e., producers and importers that are legally responsible for the quality of transportation fuels in California), rather than downstream distributors and fueling stations. However, under specified conditions, the regulated party may be another entity further downstream that can be held responsible for the carbon intensity of the fuels or blendstocks that they dispense in California.

For gasoline, diesel, and other liquid blendstocks (including oxygenates and biodiesel), the regulated party will generally be the producer or importer of the fuel or blendstock. With regard to compressed and liquefied natural gas derived from petroleum sources (fossil CNG and fossil LNG, respectively), the regulated party for fossil CNG will generally be the utility company, energy service provider, or other entity that owns the fuel dispensing equipment; for fossil LNG, it is the entity that owns the fuel when it is transferred to the fuel dispensing equipment in California. For other gaseous fuels (biogas/biomethane, hydrogen), the regulated party will generally be the person who produces the fuel and supplies it for vehicular use. For electricity, the regulated party will be either the load service entity (LSE) supplying the electricity to the vehicle or another party that has a mechanism for providing electricity to vehicles and has assumed the LCFS compliance obligation. The proposed regulation specifies the criteria under which a person would be deemed a regulated party for each particular fuel and how the responsibility of complying with the LCFS can be transferred.

As noted, certain persons are initially designated as regulated parties who are responsible for the LCFS compliance obligations. Except as provided in the proposal, this status as a regulated party generally remains with the initially designated party even if ownership to the fuel is transferred from one party to another. There are two major exceptions to this general rule. First, for CARBOB, the compliance obligations would generally transfer to another producer or importer, with provisions for the initial regulated party to retain the compliance obligation if so desired by the affected parties. For diesel fuel, the compliance obligations would generally transfer to another producer or importer that receives the diesel fuel from the initial regulated party before the final distribution point, with provisions for the initial regulated party to retain the compliance obligation if so desired by the affected parties.

Second, the proposal generally allows the regulated party for a fuel to transfer its compliance obligations by written instrument to another party under specified conditions; the buyer or recipient of the transferred fuel, in turn, becomes the regulated party for that fuel. For a variety of reasons, the transfer of such compliance obligations, along with the potential for generating and selling credits, may be desirable for a company, and the proposal allows such transfers.

The following sections describe staff's analysis for identifying the regulated party for all fuels considered under the LCFS.

a. Regulated Parties for Gasoline and Diesel

For gasoline and diesel fuel (i.e., "traditional" transportation fuels), crude oil is taken from the ground and then transported to a refinery where it is processed into various refinery products, including material that eventually goes into gasoline and diesel fuels. California refineries produce California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB), which is transported through pipelines, blended with ethanol at distribution terminals, and distributed to retail outlets as finished gasoline.

The CaRFG3 regulations describe the standards applicable to all gasoline produced or imported into California.[37] Imported gasoline must be CaRFG3 compliant. Enforcement is done initially at the distribution terminals and, if necessary, continued further downstream up to the final distribution facilities. However, as described earlier, CaRFG3 provides standards that can be enforced through quantitative analysis. Fuel quality can be tested and compliance can be easily determined. For the LCFS regulation, however, the definition of regulated parties must also take into consideration the availability of carbon intensity data and the extent to which the data are verifiable.

Currently, seven large oil companies supply about 90 percent of the gasoline sold in California. Producers and importers are already subject to CaRFG3 regulations and are also considered to be the regulated parties for the federal Renewable Fuel Standard

[37] Title 13, California Code of Regulations, section 2260 et seq.

(RFS2). Therefore, it seems logical to make them the regulated parties for LCFS as well.

Through staff analysis and discussions with stakeholders and ARB Enforcement personnel, staff proposes that a modified approach to regulation at the producer and importer is likely to be the most administratively feasible approach and has the advantage of consistency with existing federal regulations. Thus, for gasoline, diesel, and other liquid blendstocks (including oxygenates and biodiesel):

- The regulated party is the producer or importer of the fuel or blendstock, or certain recipients, as specified in the regulation;
- Upon transfer of title to the fuel, the obligation to maintain compliance with the LCFS regulation may flow from the transferor to the recipient (i.e., the transferee). For example, the compliance obligation would flow from the regulated party to the recipient if the recipient is another producer or importer. However, the parties may enter into a contract for the transferor to retain the compliance obligation (along with the credits and deficits for the transferred fuel). The transfer document would be required to clearly state either that:

    - The recipient accepts it is now the regulated party that is responsible for the acquired fuel or blendstock and for meeting the requirements of the LCFS regulation for the transferred fuel or blendstock. In this case, the transfer document would need to specify the volume and average carbon intensity of the transferred fuel; or
    - The transferor has elected to remain the regulated party for that fuel or blendstock.

b. Regulated Parties for Natural Gas (CNG, LNG, and Biogas)

The general production and distribution path for most fossil CNG is as follows. Natural gas, after extraction from the production well, may be treated to bring it up to gas pipeline specifications at a processing plant. The gas is then sent through the transmission system to the “city gate,” where it is decompressed and odorized. The gas is then sent to the fueling station via the low-pressure distribution system.

There may be several approaches for choosing the appropriate regulated party. In selecting the regulated party for fossil CNG, staff focused on identifying the entity in the production and distribution process that:

- Is as far downstream in the process without involving numerous end users to the extent feasible;
- Involves an actual physical facility or other presence within California for jurisdictional purposes;
- Has a relative low number of potential facilities that enforcement staff need to visit; and

- Has access to records that would provide insight on the upstream steps so that ARB staff can verify the lifecycle carbon intensity that is claimed by the regulated party.

Given the above goals and the process by which CNG is produced and imported into California, staff proposes that the regulated party for fossil CNG be the person or entity that owns the fuel dispensing equipment in California.

In most cases, the regulated party would be the local utility company. However, if the gas is purchased from an energy service provider (ESP) or other entity that owns the fuel dispensing equipment, the ESP or the owner of dispensing equipment will be the regulated party since title to the gas would belong to them, and they are providing the gas for transportation use. In this case, the local utility company is serving only as a conduit for the gas to be transported at the behest of these entities. The ESP or the owner of dispensing equipment are providing the gas for transportation use, is responsible for the gas quality, and therefore it should be the regulated party in such cases.

For LNG as a transportation fuel, production methods and fuel providers can vary. At present, LNG for motor vehicle fuel use is derived via two main routes. These are liquefaction of pipeline natural gas, which may be used directly at the source of liquefaction or involve truck transport of the LNG to a separate end-user, and the liquefaction and direct-use of bio-methane derived from landfill gas. Other production routes for LNG are possible, and are briefly stated below:

- Liquefaction and direct use of bio-methane derived from anaerobic digestion. Here, anaerobic digestion includes stand-alone digesters receiving one or more types of biodegradable, organic residue; digesters located on dairy, cattle and pig farms; and water treatment/wastewater treatment plant facilities;
- Truck transport of liquefied bio-methane;
- Pipeline transmission of bio-methane, which later is used as LNG;
- Truck transport of LNG received from LNG shipping of NG derived from remote sources; and
- Re-gassed LNG that is transmitted by pipeline before being re-liquefied for motor vehicle fuel use.

Fuel providers can also vary. Although LNG service stations are privately held and operated by fleets, some also provide public access. A few LNG stations also provide CNG. At present LNG used in the State at LNG service stations is either transported by truck or provided directly from landfill gas (for example, the Waste Management, Inc. landfill gas-to-LNG demonstration project). However, initiatives are underway to provide LNG from pipeline natural gas, particularly in the northern part of the State, where gas quality issues are currently not a concern.

The sources of natural gas used for the production of CNG and LNG tend to be same; only the end application and lifecycle steps tend to vary. Both can be produced from any source of fossilized natural gas. These can include associated gas wells, non-associated gas wells, and coal-bed methane deposits. The source of natural gas can either be domestic and pipeline-based, or it can be imported and either pipeline or LNG-derived from remote natural gas. LNG can also be produced from biogas, landfill gas, or even manufactured gas.

The lifecycle pathways for LNG and CNG share some similarities, but they also have important differences. CNG production typically involves four life cycle segments- production, processing, transmission and distribution, and only requires compression at the point of end-use. In contrast, depending upon the way the LNG is sourced, its production may involve as few as four life cycle segments (production, processing, liquefaction and shipping/truck transport) and as many as nine lifecycle segments before the point of end-use. Finally, it is possible at the point of end-use to produce CNG from LNG, which further complicates the analysis of lifecycle pathways.

Based on the above considerations, staff proposes that the regulated party for fossil LNG be the person or entity that owns title to the LNG when it is transferred to the fuel dispensing equipment in California.

For biogas CNG and biogas LNG, staff believes it is important to provide regulated party status for persons producing such fuels. This will allow those producers to retain the ability to generate credits for such fuels, even if the biogas CNG or LNG is blended with fossil CNG or LNG. Therefore, for biogas CNG and biogas LNG, staff proposes that the regulated parties for those fuels be the producers of the fuel.

c. Regulated Parties for Electricity

Electricity in California is delivered to customers by Load Servicing Entities. Load Servicing Entities are composed of public utilities and investor owned utilities. In the electricity delivery system, Load Servicing Entities have the most comprehensive knowledge of emissions associated with the fuel lifecycle that will influence the carbon intensity. Load Servicing Entities also have the most influence on the availability, cost, convenience and public knowledge of electricity as a transportation fuel. Staff therefore believes Load Servicing Entities will most often be the regulated parties for electricity provided under the regulation. However, Load Servicing Entities are not the only potential regulated parties. There may be cases where a separate entity has contracted with the Load Servicing Entity to install charging stations for electric transport. In these cases, the entity supplying the electricity to the vehicle would become the regulated party, as specified in the proposal.

Unlike most liquid fuels, electricity is consumed in sectors that are both regulated and unregulated by the LCFS. The regulated party would be responsible only for electricity that is delivered to vehicles. Therefore, the quantification of electricity used as a transportation fuel is a critical consideration in the design of the LCFS.

Existing electricity generation infrastructure should be able to support a high level of plug-in hybrid electric vehicle (PHEV) and battery electric vehicle (BEV) penetration, particularly if off-peak refueling is encouraged. In the case of private residences, this could be achieved by offering rate incentives and by supplying advanced direct metering systems. Direct meters are capable of detecting electric vehicle electricity consumption only.

Direct meters can be installed as separate electricity meters associated with garaged electric vehicles. However, this type of refueling is not practical for many Californians living in urban areas or apartment buildings. In addition, many electric vehicle owners will require the option to refuel away from home as necessary. To provide electricity away from home, a network of charging stations can be established by municipalities and parking lot owners in central public areas. In any case, public charging stations and charging stations installed in apartment complexes will likely be necessary for high PHEV and BEV penetration.

The proposal's metering requirements vary depending on the type of charging facility involved. Because private fleet and public-access charging facilities will be supplying electricity only to electric vehicles, the proposal requires for these facilities only the total amount of electricity dispensed for transportation use (in KW-hr) in each compliance period. On the other hand, electricity supplied to residential charging facilities can supply both transportation electricity and non-transportation electricity (i.e., for all other electricity uses in a home). Thus, for residential charging facilities, the proposal requires direct metering of the electricity provided for transportation purposes. However, to reduce the costs of installing direct metering, staff may consider amendments to allow alternative measurement methods in lieu of direct metering for a specified period of time (i.e., in the early years of the LCFS program when PHEV/BEV penetration is lower). Such alternatives may include meters installed on individual electric vehicles or other methods for measuring the amount of electricity dispensed.

Staff proposes Load Servicing Entities (LSE) and other providers of electricity services serve as regulated parties for the LCFS regulation for electricity used for transportation purposes. The compliance obligation can be transferred by contract to another party that assumes the responsibility for meeting the requirements of LCFS regulation. Such downstream entities identified in the proposal include electricity services suppliers (those supplying bundled infrastructure and other related services); certain owners and operators of electric charging equipment; and homeowners that have their own electric charging equipment.

d. Regulated Parties for Hydrogen or Hydrogen Blends

Regulating hydrogen use by vehicles presents some challenges, due primarily to the variety of hydrogen production sources and distribution channels. Currently, 95 percent of the hydrogen produced in the United States (approximately nine million tons per year) is generated by steam methane reformation of natural gas feedstock. Hydrogen can also be generated by other thermal processes such as gasification of coal or biomass, reformation of renewable liquid fuels or high temperature water splitting. Electrolytic processes (using electricity from grid, solar, or wind to split water) and photolytic processes (using light energy to split water) are also potential sources for hydrogen as a transportation fuel.

Hydrogen can be generated on-site at the fueling station or off-site at a production facility and trucked to the station as compressed gas or as a liquid. Hydrogen pipelines are also under development with approximately 700 miles of pipeline currently operating. Research is focused on overcoming technical concerns related to pipeline transmission, including the potential for hydrogen pipelines to become embrittled (including welds); the need to control hydrogen permeation and leaks; and the need for lower cost, more reliable, and more durable hydrogen compression technology.

For purposes of the LCFS, the point of fuel delivery to vehicles can be considered to be the point of sale. Since there are diverse production and delivery methods with a range of differences in GHG emissions, identifying the regulated party would center on which entity produces and supplies the hydrogen for transportation use in California.

Thus, for hydrogen and hydrogen blends, staff proposes that:

- The regulated party is the owner of the finished fuel at the time blendstocks are blended to produce the finished fuel.
- Upon transfer of title to the finished fuel, the obligation to maintain compliance with the LCFS regulation remains with the transferor. However, the parties may enter into a contract for the transferor to transfer the compliance obligation to the transferee (along with the credits and deficits for the transferred fuel). The transfer document would be required to clearly state:

    - The volume and average carbon intensity of the transferred fuel; and
    - 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.

3. Requirements for Reporting

Under the LCFS, each regulated party must report to ARB a specified set of information, including carbon intensity, fuel quantity, and other information for each fuel or blendstock supplied in California on a quarterly and yearly basis. Any party that voluntarily opts into the LCFS to generate credits must also submit a quarterly and yearly report. The reports are due according to the schedules specified in the proposed LCFS regulation.

While quarterly reports are used to gauge progress and for credit generation, a regulated party must also submit an annual report covering the current year for determination of compliance by April 30th of the following year. The annual report must be submitted to the Executive Officer, demonstrating the yearly aggregated fuel quantity, the carbon intensity associated with the fuel or blendstock, and additional supporting documents or contracts for each fuel or blendstock supplied in California. In addition, credit transactions with other regulated parties and any prior year credit obligations are required to be reported. The Executive Officer will determine whether the regulated party complies with the LCFS based on this annual report.

Staff is developing an online, interactive LCFS Compliance and Reporting Tool (CRT) that will be used for reporting, credit banking, and credit transactions during the implementation of the LCFS. This tool is discussed in Chapter IX. The CRT will serve as the central tool to facilitate the large quantity of information submission and validation that will be required under the LCFS, in addition to serving as a communication tool between the Executive Officer and regulated parties. The first year of the program is intended as a "break in" reporting year, which will allow both the regulated parties and ARB program staff to acclimate to the LCFS rule's intricacies and to identify any programmatic changes that may be needed as the program is implemented.

4. Requirement to Maintain Adequate Credit Balance

For each compliance period, a regulated party must maintain an adequate number of credits in the account in order to comply with the LCFS. The credit balance for a regulated party is an accounting balance sheet that takes into consideration all the credits generated for providing a fuel or a blendstock, the amount of credits carried over from the previous compliance period, the amount of credits acquired, the amount of deficits generated, and the amount of credits sold, exported or retired. All credits and deficits are reported in units of metric tons of CO_2 equivalent ("MT"). The credit balance is computed as follows:

$$\begin{aligned} CreditBalance &= Credits^{Gen} + Credits^{CarrivedOver} + Credits^{Acquired} \\ &+ Deficits^{Gen} - Credits^{Sold} - Credits^{Exported} - Credits^{Retired} \end{aligned} \qquad \text{V.1}$$

where

$Credits^{Gen}$ are the total credits generated calculated according to Equation V.3 in section V.F of this report.

$Credits^{CarrivedOver}$ are the credits or deficits carried over from the previous compliance period.

$Credits^{Acquired}$ are the credits purchased or otherwise acquired in the current compliance period.

$Deficits^{Gen}$ are the total deficits generated calculated according to Equation V.4 in section V.F of this report.

$Credits^{Sold}$ are the credits sold in the current compliance period.

$Credits^{Exported}$ are the credits exported to programs outside the LCFS for the current compliance period.

$Credits^{\text{Re}itred}$ are the credits retired within the LCFS for the current compliance period.

For each compliance period, a regulated party uses the carbon intensity value of the fuel or blendstock and fuel quantity information to calculate the amount of credits/deficits generated under the gasoline and/or diesel standard for *each* fuel or blendstock, according to Equation V.5 in section G of this report. The total credits or deficits generated under either the gasoline or diesel standard is summed across all the fuels or blendstocks, according to Equations V.3 and V.4 in section G. These become the $Credits^{Gen}$ and $Deficits^{Gen}$ terms in the credit balance equation above. All other sources of credits and deficits are then added and a final credit balance value is determined for the compliance period. Appendix D of this report contains illustrative examples that demonstrate LCFS credit balance calculations.

For a compliance period, depending on the value of the current credit balance and regulated party's previous compliance status, a regulated party could fall within one of three categories below:

a. Meets LCFS Credit Balance

If a regulated party has acquired or generated enough LCFS credits such that the $CreditBalance$ is greater or equal to zero for a given compliance period, the regulated party has demonstrated compliance with the LCFS carbon intensity requirements. The $CreditBalance$ for a given compliance period may be rolled over to the next compliance period as $Credits^{CarrivedOver}$.

b. Small Credit Balance Shortfall ("In Deficit")

If a regulated party has not generated, acquired, or carried over sufficient LCFS credits to meet its obligation for the given compliance period, a regulated party is in deficit status if the following conditions are met:

- The regulated party has not incurred a negative $CreditBalance$ in the previous compliance period, and
- The total credits in the account must be at least 90 percent of the total deficits for the current compliance period. The following equation shows the credit to deficit ratio:

$$\left|\frac{Credit^{Gen} + Credits^{CarrivedOver} + Credits^{Acquired}}{Deficit^{Gen} - Credits^{Sold} - Credits^{Exported} - Credits^{\text{Re}itred}}\right| \geq 90\% \qquad \text{V.2}$$

The regulated party meeting the two conditions above may carry over the negative $CreditBalance$ from one compliance period to the next compliance period automatically without incurring a penalty. Staff is proposing this as a compliance flexibility provision that is similar to what is allowed under the federal RFS2. The regulated party has until December 31 of the *next compliance period* to clear the carried-over negative $CreditBalance$. The additional deficit clearance time given to the regulated party is called a Deficit Clearance Period, during which the regulated party must have enough credits to clear the carried-over deficits and meet the obligation of the new compliance period. For instance, if a regulated party incurred a negative $CreditBalance$ of -100 MT in 2012 but was in compliance in 2011 and has a credit to deficit ratio of 95% in 2012, the regulated party may carry over the -100 MT to 2013 automatically without incurring any penalties. During 2013, the regulated party must clear the -100 MT and meet the obligations of 2013.

c. Large Credit Balance Shortfall ("In Violation")

If a regulated party has met one of the conditions below, then the regulated party is considered to be in violation of the LCFS and subject to the penalties and enforcement actions authorized by the LCFS regulation.

- Incurred a negative $CreditBalance$ for two or more consecutive years; or
- Incurred a credit to deficit ratio of less than 90 percent for a given a compliance period.

A discussion of penalties is presented in Chapter IX.

5. Requirement for Demonstrating Evidence of Physical Pathway

It is important to ensure that low carbon fuels and blendstocks produced outside of California are actually the source of finished fuels used in the State. Therefore, regulated parties will be required under the proposal to establish physical pathway evidence for transportation fuels subject to the LCFS. For each transportation fuel that a regulated party is responsible for under the LCFS, this could involve a four-part showing:

- A one-time demonstration that there exists a physical pathway by which the transportation fuel is expected to arrive in California. This includes applicable combination of truck delivery routes, rail tanker lines, gas/liquid pipelines, electricity transmission lines, and any other fuel distribution routes that, taken together, accurately account for the fuel's movement from the generator of the fuel, through intermediate entities, to the fuel blender, producer, or importer in California;
- Written evidence, by contract or similar evidence, showing that a specific volume of a particular transportation fuel with known carbon intensity was inserted into the physical pathway as directed by the regulated party;

- Written evidence, by contract or similar evidence, showing that an equal volume of that transportation fuel was removed from the physical pathway by the regulated party for use as a transportation fuel in California; and
- An update to the initial physical pathway demonstration whenever there are modifications to the initially demonstrated pathway.

G. LCFS Credits and Deficits

The LCFS is structured much like an emissions reduction credit program in which credits are awarded based on fuel performance that exceeds a regulatory standard. The LCFS includes a flexible combination of fuel-vehicle systems and awards credits to the fuel provider if the total emissions generated by the supply and consumption of the fuel are below those of the corresponding gasoline or diesel standards. Beginning 2011, regulated parties could start generating credits on a quarterly basis. These credits can be banked indefinitely and used for compliance purposes, sold to other regulated parties, and purchased and retired by regulated parties. In addition, the credits can be exported to other GHG emissions reductions programs such as AB 32, subject to the requirements of these GHG programs.

1. Calculation of Credits and Deficits Generated

This section covers the overall method for calculating the credits and deficits generated or the $Credits^{Gen}$ and $Deficits^{Gen}$ terms in the credit balance in equation V.1.

In the LCFS regulation, the amount of credits generated (or the deficits incurred) by a regulated party contributes to the overall credit/deficit balance used for the determination of compliance for a regulated party. For each compliance period, a fuel provider calculates the amount of credits and deficits generated for the amount of fuel supplied as either a gasoline or diesel fuel replacement. The total credits and deficits generated under the gasoline and diesel standard are respectively summed over all the fuels and blendstocks supplied by the regulated party. All credit and deficit are reported in units of metric tons of CO_2 equivalent (MT). The equations V.3 and V.4 illustrate the calculation.

$$\boxed{Credits^{Gen}(MT) = \sum_{i}^{n} Credits_i^{gasoline} + \sum_{i}^{n} Credits_i^{diesel}} \qquad (V.3)$$

$$\boxed{Deficits^{Gen}(MT) = \sum_{i}^{n} Deficit_i^{gasoline} + \sum_{i}^{n} Deficit_i^{diesel}} \qquad (V.4)$$

where:

$Credits^{Gen}$ represents the total credits (a zero or positive value);

$Deficit^{Gen}$ represents the total deficits (a negative value);

i is the fuel or blendstock index; and

n is the total number of fuels and blendstocks provided by the regulated party in a compliance period.

For each applicable fuel under the LCFS, credit/deficit is determined by the overall performance of the fuel, indicated by the carbon intensity value, and the extent to which the fuel displaces a conventional fuel such as gasoline or diesel. The equation V.5 illustrates the calculation.

$$\boxed{(Credits\ or\ Deficits)^{XD}(MT) = \left(CI_{standard}^{XD} - CI_{reported}^{XD}\right) \times E_{displaced}^{XD} \times C} \qquad (V.5)$$

where:

$(Credits\ or\ Deficits)^{XD}(MT)$ indicates the amount of LCFS credits generated (a zero or positive value), or deficits incurred (a negative value), in metric tons of CO_2 equivalent, by a finished fuel or blendstock under the gasoline standard (*XD*=”gasoline”) or diesel standard (*XD*=”diesel”); and

C is the factor used to convert credits to units of metric tons and has the value of:

$$C = 1.0x10^{-6} \frac{(MT)}{(gCO_2e)}$$

The term $CI_{standard}^{XD}$ indicates the carbon intensity of the gasoline or diesel standard for a given year, which is established as part of the LCFS. Notice the amount of credits generated depends on the extent to which the carbon intensity value of a fuel is below that of the standard.

For each alternative fuel, the amount of credits/deficits generated is also determined by the amount of conventional gasoline or diesel fuel that is displaced, indicated by the parameter $E^{XD}_{displaced}$. The amount of conventional energy displaced is determined using a fuel displacement factor called the Energy Economy Ratio (EER) which compares the fuel economy of an alternative fuel vehicle to that of a conventional gasoline vehicle. In addition, the carbon intensity of alternative fuels is adjusted with the EER value of the alternative fuel vehicle. The more energy efficient fuels and vehicles travel more miles per unit of energy input to the vehicle, thus resulting in less fuel consumption and CO_2 emissions (carbon intensity). Thus, the carbon intensity is dependent on both the emissions per unit of energy consumed and the fuel economy of the vehicle.

For each fuel or blendstock:

$$CI^{XD}_{reported} = \frac{CI_i}{EER^{XD}}; \quad \text{and} \quad E^{XD}_{displaced} = E_i \times EER^{XD}_i$$

where:

$CI^{XD}_{reported}$ is the adjusted carbon intensity value reported for credit determination, in gCO_2e/MJ;

CI_i is the unadjusted carbon intensity value, in gCO_2e/MJ, determined by a CA-GREET pathway or a custom pathway and incorporates a land use modifier (if applicable);

$E^{XD}_{displaced}$ is the total amount of gasoline (*XD*=”gasoline”) or diesel (*XD*=”diesel”) fuel energy displaced, in MJ, by the use of an alternative fuel;

E_i is the energy of the fuel or blendstock, in MJ, determined from the energy density conversion factors in Table V-2.

EER^{XD}_i is the dimensionless EER relative to gasoline (*XD*=”gasoline”) or diesel fuel (*XD*= “diesel”) as listed in Table V-3. For a vehicle-fuel combination not listed in Table V-3, EER^{XD}_i=1 is used. Chapter IV contains more information on the EER numbers used in the proposed regulation.

Appendix D of this report shows sample calculations of credits and deficits generated for regulated parties providing a single or multiple fuels and blendstocks.

Table V-2
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)
Neat denatured Ethanol (gal)	80.53 (MJ/gal)
Neat Biomass-based diesel (gal)	126.13 (MJ/gal)

Table V-3
EER Values[38] 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 / ICEV	1.0	CNG or LNG	0.9
Electricity / BEV, or PHEV	3.0	Electricity / BEV, or PHEV	2.7
H2 / FCV	2.3	H2 / FCV	1.9

(BEV = battery electric vehicle, PHEV=plug-in hybrid electric vehicle, FCV = fuel cell vehicle, ICEV = internal combustion engine vehicle)

H. Retaining, Trading, and Borrowing of LCFS Credits

As noted, beginning 2011, regulated parties could start generating credits on a quarterly basis. Both the gasoline and diesel standards are backloaded so that, if necessary, credits that were banked in the early years will help with compliance in the later years.

[38] Chapter IV provides additional information on these EER values.

1. 3rd Party Credit Acquisition and Trading

One of the key cost-reduction LCFS design elements is the creation of a market for carbon intensity credits. Under a market-based system, regulated parties would be able to buy and sell credits. To keep LCFS credit transactions simple in the early years and to ensure there are an adequate number of credits in the program, staff proposes that 3rd party entities not be allowed to purchase, sell, and retire LCFS credits at the onset of the LCFS. As part of the periodic reviews, staff will re-evaluate the ability of 3rd party entities to participate in LCFS credit transactions.

2. Importing and Exporting Credits to Other Markets

Credit import/export is the process of bringing credits generated in one GHG emission reduction program into a complementary, external program for compliance under that program and vice versa. The proposed regulation allows for the exporting of credits to other GHG trading programs, subject to the requirements of those other programs. However, the staff proposal prohibits the imports of credits from other programs outside the LCFS.

The range of responses from stakeholders on this issue is diverse. Several stakeholders caution that credits exported to AB 32 could undermine the integrity of the AB 32 cap and force the LCFS to be considered a substitute policy rather than a complementary policy. They further argue that since transportation should be already included in an economy-wide market, trading between the two programs would amount to double counting. Other stakeholders believe that reductions in areas overlapping both the LCFS and AB 32 should receive credits under both programs, thus eliminating the need for exports. Still others support the export of LCFS credits and see it as a mechanism to ensure there is a market for the generated credits. ARB staff believes that the LCFS should not restrict the use of these credits in other markets. However, the use of these credits will be dictated by the requirements of those other programs, including the AB 32 trading programs. Such flexibility may incentivize the development of innovative low-carbon fuel technologies within the LCFS.

ARB staff is proposing not to allow the use of GHG credits generated outside the LCFS program to be used in the LCFS program. This is to ensure that improvements in the LCFS fuel pool occur. As a possible exception, however, staff will continue to evaluate the feasibility and effectiveness of allowing credits generated from marine and aviation transportation areas, which are not currently included in the LCFS fuel pool, to be used in the LCFS program. ARB staff will provide an update on the potential use of GHG credits from lower carbon marine and aviation fuels to be used in the LCFS program, at the scheduled milestone review point.

3. Borrowing of Credits

Under a credit borrowing system, credits would be ‘borrowed’ from anticipated future emissions reductions in order to meet compliance in the present. Funds raised from the sale of borrowed credits could be used to increase a regulated entity's near-term ability to invest in the development of lower-carbon fuels. These increased investments could bring lower carbon fuels to market sooner than might otherwise be possible. Credit borrowing systems are relatively untested, and any attempt to implement one in California could be problematic. Staff is proposing to not allow the borrowing of LCFS credits.

I. 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 all of the direct 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. The second part considers other effects, including those caused by changes in land use. For some crop-based biofuels, staff has identified land use changes as a significant source of additional GHG emissions. Therefore, staff is proposing that emissions associated with land use changes be included in the carbon intensity values assigned to those fuels in the proposed regulation. No other significant 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.

As discussed in the last section, staff used the CA-GREET model as the primary method for calculating carbon intensity values for various transportation fuels. CA-GREET is essentially a very large spreadsheet that incorporates many specific numeric values that allow for the calculation of the life cycle GHG emissions associated with producing, transporting, and using various fuels. Staff used CA-GREET to develop specific carbon intensities for a number of different pathways. For some fuels, multiple pathways were developed that represent differences in how and where the fuel is produced.

To assess the emissions from land use changes, staff used the Global Trade Analysis Project (GTAP) to estimate the GHG emissions impact. The GTAP model is also discussed in Chapter IV. In general, the model evaluates the worldwide land use conversion associated with the production of crops for fuel production. Different types of land use have different rates of storing carbon. In general, multiplying the changes in land use times an emission factor per land conversion type results in an estimate of the GHG emissions impacts of land conversions.

The proposed regulation has several different methods for establishing carbon intensities. The first method, referred to as Method 1, establishes values in a Lookup Table for a number of specified fuel pathways. Regulated parties may choose to use these pathways to calculate credits and deficits. The staff is proposing that the Board approve this Lookup Table. The proposed regulation establishes that the Executive Officer may approve subsequent amendments to the Lookup Table after a specified public process.

Under specified conditions, regulated parties may also obtain Executive Officer approval to either modify the CA-GREET model inputs to reflect their specific processes (Method 2A) or to generate an additional pathway using CA-GREET (Method 2B). For both Method 2A and 2B, there is a scientific defensibility requirement for the regulated party to meet before the Executive Officer can approve new values. For Method 2A, there is an additional provision that requires a substantial change (5.00 g CO_2e/MJ decrease in source-to-tank CI) relative to the analogous value calculated for that pathway under Method 1.

For all requests under Methods 2A and 2B, ARB staff will conduct analysis or modeling to determine the new pathway's impact on total carbon intensity due to indirect effects, including land-use changes. This analysis will be performed using the GTAP model or other model determined by the Executive Officer to be at least equivalent to the GTAP model.

For CARBOB, gasoline, and diesel fuel, there are specific provisions with regard to the method for determining carbon intensity values, depending on whether the crude oil used to make such fuels is derived from crude oils with high carbon intensity relative to the average carbon intensity of crude oils used in California refineries. Examples include certain crude oils produced from oil sands, oil shale, or other high carbon-intensity crude oils. With regard to CARBOB, gasoline, and diesel fuel made from crude oil extracted from any source other than these high carbon-intensity crude oils, the regulated party would be required to use the carbon intensity specified in the Lookup Table for that fuel.

By contrast, for CARBOB, gasoline, and diesel fuel made from high carbon-intensity crude oil, the regulated party would be required to use the carbon intensity value, if any, which is specified in the Lookup Table for that particular pathway. If there is no carbon intensity value specified for a particular high carbon-intensity crude oil, the regulated party could use Method 2B (with Executive Officer approval) to generate an additional pathway for this type of crude.

Alternately, the regulated party could use the standard Lookup Table value for CARBOB, gasoline, or diesel for fuel derived from non-high carbon intensity crude oil, but only if the regulated party can demonstrate to the Executive Officer that its crude production and transport carbon-intensity value has been reduced to a specified level and meets other specified criteria. To this end, staff is proposing that any regulated party, using a high carbon-intensity crude oil (> 15 g CO2e/megajoule) brought into California that is not already part of the California baseline crude mix, would have to report and use the actual carbon intensity for that crude oil unless the party demonstrates that it has reduced the crude oil's carbon intensity below 15 g CO2e/megajoule using carbon-capture-and-sequestration (CCS) or other method. Upon this demonstration, the regulated party would be permitted to use the average carbon intensity value for the California baseline crude mix (i.e., crude oils currently used in California refineries).

The proposed uses of Method 2A and 2B are subject to public review under the proposal. In other words, the Executive Officer may not approve a carbon intensity value proposed pursuant to Method 2A or 2B unless the proposed method and associated information submitted in support of that method has been disclosed to the public and available for public review for the prescribed time period. Trade secrets, as defined under State law, that are submitted would be treated in accordance with established ARB regulations and procedures (17 CCR §§ 91000-91022) and the Public Records Act (Government Code § 6250 et seq.).

J. Requirements for Multimedia Evaluation

1. Statutory Requirements

Senate Bill 529, enacted in 1999 and set forth in Health and Safety Code (H&S) section 43830.8 ("the statute"),[39] generally prohibits ARB from adopting a regulation establishing a specification for motor vehicle fuel unless the regulation is subject to a multimedia evaluation by the California Environmental Policy Council (CEPC). (Stats. 1999, ch. 813; SB 529, Bowen.) Pursuant to Public Resources Code section 71017(b), the CEPC was established as a seven-member body comprised of the Secretary for Environmental Protection; the Chairpersons of the ARB, State Water Resources Control Board, and Integrated Waste Management Board; and the Directors of the Office of Environmental Health Hazard Assessment, the Department of Toxic Substances Control, and the Department of Pesticide Regulation. Key components of the evaluation process are the identification and evaluation of significant adverse impacts on public health or the environment and the use of best available scientific data.

"Multimedia evaluation" means the identification and evaluation of any significant adverse impact on public health or the environment, including air, water, or soil, that may result from the production, use, or disposal of the motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specifications. H&S §43830.8(b).

The statute generally provides that ARB may adopt a regulation establishing a motor-vehicle fuel specification without undergoing the prescribed multimedia evaluation process if the CEPC, following an initial evaluation of the proposed regulation, finds that the regulation will not have significant adverse impacts on public health or the environment.

2. Applicability of H&S §43830.8 to the LCFS Regulation

The provisions in H&S §43830.8 are relatively straightforward for a fuel regulation that unquestionably constitutes a fuel specification. However, before the substantive requirements of the statute can be discussed, we first need to address an important threshold question in this case: Does the statute apply to the LCFS regulation itself, or

[39] All statutory references in this chapter are to H&S §43830.8 unless otherwise noted.

does it apply onl y to subsequent ARB rulemakings establishing new or amended motor-vehicle fuel specifications to implement the LCFS program?

a. H&S §43830.8 Applies to ARB Adoption of Regulations that Establish Specifications for a Motor Vehicle Fuel

By its terms, the statute clearly focuses on prohibiting ARB from adopting regulations that establish specifications for motor vehicle fuels unless the regulation has been subjected to a multimedia evaluation as specified. Presumably, this is to avoid, among other things, requiring ARB to conduct a multimedia evaluation for rule amendments that are merely technical in nature and have no substantive effect on motor vehicle fuel specifications. Another possibility is that the Legislature did not want to require a multimedia evaluation whenever ARB adopted fuel *use* requirements, which affect the use of a fuel and operation of equipment using that fuel, rather than affecting the fuel itself.[40] A third possibility is that the Legislature did not want to require multimedia evaluations for emissions averaging or similar regulatory schemes for which an enforceable goal is set but the exact methods for achieving that goal are not specified by the regulation (i.e., through motor vehicle fuel specifications).

Further, the Legislature presumably used the term “specification,” rather than more broad terms such as “standard” or “requirement,” to express an intent to focus on those regulations in which ARB is proposing to dictate what is added (or prohibited from being added) into a motor vehicle fuel. This would be consistent with the legislative history of SB 529, which was promulgated after fuel producers began to use methyl *tert*-butyl ether (MTBE) in gasoline in the 1990s to meet ARB oxygenate requirements. The Legislature enacted SB 529 after MTBE was subsequently shown to leak out of underground storage tanks unexpectedly into aquifers.

With these considerations in mind, the next questions that follow are, “What is a motor vehicle fuel specification?” and “Is the LCFS a regulation that establishes a fuel specification for motor vehicle fuels?”

b. The LCFS Regulation Does Not Establish a Specification for Motor Vehicle Fuels

For purposes of this discussion, the primary LCFS requirement of interest is the requirement for regulated parties to reduce their average carbon intensity by 10 percent.[41] This 10 percent reduction in overall carbon intensity would cover the party’s overall motor vehicle fuel pool, including all fuels subject to the LCFS, as well as

[40] An example is the California requirement for locomotives and commercial harbor craft to use California ultralow sulfur diesel. 13 CCR §2299 and 17 CCR §93116.

[41] That is, the regulated party’s carbon intensity must be no greater than the carbon intensity (CI) for gasoline or diesel as the CI for those fuels are reduced by 10% between 2010 and 2020 in accordance with the proposed regulation’s compliance schedule (the gasoline CI applies generally for light duty vehicles and the diesel CI for heavy duty vehicles).

any credits/deficits from overcompliance and undercompliance with the requirement in a given compliance period.

Unfortunately, the statute provides no explicit definition for “specification.” However, there is evidence indicating that the Legislature intended the term “specification” as a reference to the permissible ingredients that comprise a fuel (i.e., the fuel’s “composition”). In H&S §43018, a statute last amended nine years before SB 529 was enacted, the Legislature mandated that ARB:

> “adopt standards and regulations which will result in the most cost-effective combination of control measures on all classes of motor vehicles and *motor vehicle fuel*, including, but not limited to, all of the following:…(4) *[s]pecification* of vehicular fuel *composition*…” [emphasis added].

H&S §43018(c)(4) [Added Stats. 1988, ch. 1568; amended Stats. 1989, ch. 559; amended Stats. 1990, ch. 932].

In this context, the Legislature seems to use the term “specification” as a subset of motor vehicle “standards,” “regulations,” and “measures.” Thus, one can reasonably presume that, in the context of motor vehicle fuels, the Legislature intended the term “specification” to be an ARB mandate on a vehicular fuel’s permissible composition, rather than on the production process for the fuel.

This view of the legislative intent is further supported when one looks at the common usage for the term “specification” in the area of motor vehicle fuels. To this end, we first discuss the general characteristics of a specification and then look at several examples of existing ARB specifications. From these examples, it is possible to glean whether the Legislature intended for a regulation like the LCFS to trigger the multimedia evaluation requirement.

The American Heritage (4th Ed.) dictionary(73) defines “specification” as follows:

> “*A detailed, exact statement of particulars, especially a statement prescribing materials, dimensions, and quality of work for something to be built, installed, or manufactured.*”

This suggests that a specification is prescriptive in nature, i.e., telling the reader that material X is required in Y amount. A useful analogy is a typical cooking recipe, in which not only are the ingredients specified, but also their relative quantities. Motor vehicle fuel specifications, like cooking recipes, also specify what materials are permitted to be in a legal motor vehicle fuel and the relative quantities of those materials.

There are numerous examples of motor vehicle fuel specifications that were in existence at the time SB 529 was enacted. For instance, California’s diesel regulation in 1999 applied specifications that limited aromatic hydrocarbons to 10% by volume and 500 parts per million (ppm) sulfur in diesel.[42] Another example is the California regulation establishing specifications for E-85 (gasoline with 85% ethanol), which is presented in Table V-4.

Table V-4
Select Specifications for E-85 Fuel Ethanol

Specification	Value	Test Method
Ethanol	79 vol. % (min.)	ASTM D 3545-90
Other Alcohols	2 vol. % (max.)	ASTM 4815-89
Hydrocarbons + aliphatic ethers	15-21 vol. %	ASTM D 4815-89, and then subtract concentration of alcohols, ethers and water from 100 to obtain percent hydrocarbons
Acidity as acetic acid	0.007 mass % (max.)	ASTM D 1613-85
Total chlorine as chloride	0.0004 mass % (max.)	ASTM D 3120-87 modified for the det. of organic chlorides, and ASTM D 2988-86
Copper	0.07 mg/l (max.)	ASTM D 1688-90 as modified in ASTM D 4806-88

Source: 13 CCR § 2292.4 (adopted by ARB in 1992); footnotes omitted.

A third, more current example is the CaRFG3 regulation is presented in Table V-5.

Table V-5
Select Current Specifications for CaRFG3

Property	Flat Limits	Averaging Limits	Cap Limits
Reid Vapor Pressure, psi, max	7.00 or 6.90	--	6.40 – 7.20
Benzene vol%, max	0.80	0.70	1.10
Sulfur, ppmw, max	20	15	30 20 (2011)
Aromatic HC, vol%, max	25.0	22.0	35.0
Olefins, vol% max	6.0	4.0	10.0
Oxygen, wt%	1.8 to 2.2	--	1.8 - 3.5 0 – 3.5
T50 (temp. at 50% distilled) ^{o}F, max	213	203	220
T90 (temp. at 90% distilled) ^{o}F, max	305	295	330

Source: 13 CCR §2260 et seq.; footnotes omitted.

[42] 13 CCR §2282(a)(1)(A) and §2281(a)(1), respectively. The 500 ppm sulfur limit was reduced for most applications to 15 ppm beginning in June 2006. *Id*. at §2282(a)(2).

Of course, motor vehicle fuel specifications are not cooking recipes, as they entail highly technical properties and measurements for the affected fuels. But like a cooking recipe, all the above examples of existing fuel specifications share a common characteristic – the specifications contained in the requirements are quantifiable and measurable chemical or physical properties that are intrinsic to the final fuel itself, not how it is produced. In other words, one can take a sample of diesel and measure its sulfur and aromatic content to see if it meets the specified limits on those properties. Similarly, a sample of gasoline can be analyzed in a laboratory for its Reid vapor pressure or sulfur content. To determine compliance with the specifications for these fuels, it is irrelevant to ask how these fuels were made – the only question is whether the finished product has the desired physical and chemical properties.

In contrast, it is as important, or even more important, to know *how* a fuel or blendstock was made under the LCFS regulation than knowing the fuel's actual constituents. The LCFS requires a regulated party to achieve a specified performance reduction in its motor vehicle fuel pool's overall carbon intensity. This is the sum of all carbon intensities associated with all steps required to produce, distribute, market and use the party's fuel, plus any credits purchased, generated, or used by the party. As such, a regulated party's carbon intensity cannot be directly measured in a sample of gasoline, diesel, or any other fuel. Simply put, one cannot take a gallon of gasoline and measure its carbon intensity in a laboratory like one would for determining the fuel's boiling point.

Rather, a fuel's carbon intensity is inferred from the various steps taken to produce that fuel and the relative impacts to climate change associated with each step (vis-à-vis the steps' carbon intensity), as well as accounting for any credits used, generated, or traded by the regulated party. Thus, the relevant question for the LCFS is exactly the opposite of the above examples of actual fuel specifications: Exactly how was the product made, since the process for producing and distributing the product is what affects the product's carbon intensity?

To further illustrate, a gallon of ethanol made from corn grown and processed in the Midwest will, under a microscope or other analytical device, look identical in every material way to a gallon of ethanol processed from sugar cane grown in Brazil. Both samples of ethanol will have the same boiling point, the same molecular composition, the same lower and upper limits of flammability – in other words, both will have identical physical and chemical properties because both products consist of 100% ethanol. On the other hand, the corn ethanol made from the Midwest will have different carbon intensity than the sugar cane ethanol from Brazil. Thus, the relevant inquiry with carbon intensity is not so much what is contained in a fuel, but how was that fuel made, distributed and used.

An additional complication is that a regulated party's carbon intensity is not only reflective of its fuels' carbon intensities, but also whether any credits that are used or traded are also reflected in the party's overall carbon intensity. Thus, from the above example, even if the corn ethanol and sugar ethanol were to have identical carbon intensity, one regulated party using corn ethanol would almost certainly have a different overall carbon intensity than another party with sugar ethanol, simply because each party would have different rates of credit generation and usage.

The above considerations strongly suggest that the LCFS regulation, unlike other existing California regulations, does not establish prescriptive[43] fuel specifications. Instead, the nature of the LCFS regulation points to a rule that is much more akin to a performance[44] requirement, one that establishes an enforceable goal but does not dictate the process for how to achieve compliance with that goal. As such, ARB staff believes the LCFS regulation, by itself, does not establish motor vehicle fuel specifications; therefore, the LCFS rule should not be subject to the multimedia evaluation requirement.

c. The LCFS Regulation Does Not Affect Existing Fuel Specifications

It is important to note that, by its terms, the LCFS regulation does not modify any other existing State or federal specifications for motor vehicle fuels. Section 95480.1(e) of the proposed regulation includes a saving clause providing, in pertinent part, that:

> "*Nothing in this LCFS regulation (17 CCR §95480 et seq.) may be construed to amend, repeal, modify, or change in any way the California Reformulated Gasoline regulations (CaRFG, 13 CCR §2260 et seq.), the California Diesel Fuel regulations (13 CCR §2281-2285 and 17 CCR §93114), or any other applicable State or federal requirements. Any person, including but not limited to the regulated party as that term is defined in the LCFS regulation, subject to the LCFS regulation or other State and federal regulations shall be 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.*"

This provision was included to reflect staff's intent that the LCFS regulation, by itself, neither establishes a fuel specification nor amends any other State or federal requirements that apply to the affected fuels, including other requirements that constitute fuel specifications.

This provision also reflects staff's understanding of what will likely occur to gasoline and diesel under the LCFS regulation. To comply with the LCFS

[43] "Prescriptive standard" means a regulation that specifies the sole means of compliance with a performance standard by specific actions, measurements, or other quantifiable means. (Gov. Code §11342.590.)

[44] "Performance standard" means a regulation that describes an objective with the criteria stated for achieving the objective. (Gov. Code §11342.570.)

regulation, it is unlikely that fuel producers will change the composition and makeup of gasoline and diesel, since these are relatively mature technologies that still would need to meet applicable State and federal specifications. Instead, fuel producers are likely to choose less carbon-intensive blendstocks, such as cellulosic ethanol, to help meet their LCFS obligations.

d. There are Practical Difficulties in Conducting a Multimedia Evaluation for the LCFS Rulemaking

Even if, for the sake of argument, one were to conclude that the LCFS rule itself somehow triggers the multimedia evaluation requirement, conducting such an evaluation for the overall rule would make it practically very difficult, if not impossible, to conduct such an evaluation. Because the LCFS establishes a performance-based requirement (see above) rather than a prescriptive standard, it is very difficult for ARB to predict with certainty how regulated parties will comply with the LCFS requirement. For instance, there has been substantial mention of the use of genetically engineered algae to provide feedstock for making renewable diesel or other lower carbon intensity fuels. However, such technology is, at best, in its infancy, and no meaningful discussion of the pathways (and, by extension, the associated carbon intensity) can be made until the technology is better developed and ARB has adopted fuel specifications for such fuels.

Given these difficulties, the best that ARB staff can provide at this time is the “functional equivalent” of a multimedia evaluation. Such an equivalent can, to the extent feasible, identify and evaluate the potential adverse impacts on public health or the environment that may result from the production, use, or disposal of motor vehicle fuels that are likely to be used to meet the LCFS requirements. As fuels are developed and produced to comply with the LCFS, ARB can adopt new specifications or amend existing specifications for such fuels as needed. At that time, ARB staff plan to conduct new multimedia evaluations pursuant to H&S §43830.8.

3. Applicability of H&S §43830.8 to Post-LCFS Regulations Establishing Vehicular Fuel Specifications

Based on the above discussion, ARB staff believes that the LCFS regulation itself does not establish motor vehicle fuel specifications that trigger the multimedia evaluation requirement. However, it is clear that post-LCFS rules adopted by ARB would certainly require multimedia evaluations to the extent such rules establish new fuel specifications or modify existing ones. The LCFS regulation incorporates this principle as a pre-sale prohibition applied to fuels that are subject to an ARB specification that is modified or adopted after adoption of the LCFS regulation.[45] In such cases, regulated parties would be prohibited from selling the affected fuels in California to comply with the LCFS

[45] See proposed LCFS regulation section 95487(a).

requirements until a multimedia evaluation is approved for those fuels pursuant to H&S §43830.8.

Fuels that would not be subject to this pre-sale prohibition include the following (until such time as ARB adopts a new specification or modifies the existing specification for these fuels):

- Those fuels that were "grandfathered" in before July 1, 2000, pursuant to H&S §43830.8(h), or have not had their specifications amended since SB 529 was enacted – these include CaRFG, diesel, E85, E10, CNG, LNG;

- Those fuels for which there are no existing ARB specifications but are permitted for sale in California pursuant to regulations promulgated by the Division of Measurement Standards -- this includes biodiesel and renewable diesel; and

- Those fuels for which the California Environmental Policy Council has determined no significant adverse impacts would result from the Board's adoption of a fuel specification (under H&S §43830.8(i)).

For the 2009 rulemaking calendar, ARB staff is currently planning to propose a new motor vehicle specification for biodiesel and renewable diesel. Staff may also propose rulemakings for E85 and CNG later in the year. To the extent those rulemakings establish new specifications, multimedia evaluations may be needed pursuant to H&S §43830.8.

To comply with the requirements for multimedia evaluations that is applicable to the Low Carbon Fuel Standard:

- Staff recognizes that a full and comprehensive multimedia evaluation, in accordance with H&S §43830.8, is neither required nor practical to conduct for the LCFS rulemaking itself;

- Nevertheless, to implement the "spirit" of H&S §43830.8, staff intends to conduct the functional equivalent of a multimedia evaluation for the LCFS rulemaking to the extent feasible.

- Staff will conduct full multimedia evaluations, pursuant to H&S §43830.8 and consistent with the California Environmental Protection Agency (Cal/EPA) Guidance Document(74), prior to ARB adoption of a new fuel specification for motor vehicle fuels subject to the LCFS rule. The first of these will be rulemakings in 2009 to adopt motor vehicle fuel specifications for biodiesel and renewable diesel, which will require a multimedia evaluation. To the extent future rulemakings involving CNG, E85, or other fuels may involve the establishment of motor vehicle fuel specifications, a multimedia evaluation may be required for those rulemakings as well.

K. Cap and Trade Under the LCFS Regulation (Reserved)

Under the AB 32 Scoping Plan(6) (Scoping Plan), the Air Resources Board plans to incorporate transportation fuels into the AB 32 cap-and-trade(6)[46] program in 2015. This will require that the LCFS regulation contain provisions to facilitate the integration of the LCFS with the AB 32 cap-and-trade program. Because the AB 32 cap-and-trade program itself is currently under development, most elements of the related LCFS provision are still conceptual at this stage. For this reason, the proposed LCFS regulation contains a placeholder section in which the cap-and-trade provisions will eventually be specified.

With that said, staff believes there is merit in beginning the dialogue on how best to structure the LCFS provision. To this end, we provide in this chapter a broad overview of major elements of a LCFS cap-and-trade related provision. This discussion will necessarily be brief and general, reflecting the significant work that must be undertaken in the next few years to flesh out the complex issues involved and develop these and related concepts into regulatory text. Accordingly, we will focus on two issues: (1) the interchangeability of cap-and-trade allowances and credit trades, and (2) ARB's role in credit trading.

Interchangeability of Cap-and-Trade Allowances and Credit Trades

An issue that staff is proposing to address at this point is the extent to which LCFS credits and tradable cap-and-trade allowances can be used interchangeably to comply with LCFS and/or cap-and-trade.

On the one hand, staff proposes to allow the *export* of LCFS credits to other AB 32 programs. The LCFS credits, which will be denominated in metric tons of carbon dioxide equivalent (MT-CO2e), are based on an analysis of the transportation fuel's full, lifecycle carbon intensity. As such, the LCFS credits can be clearly documented for each step in a fuel's well-to-wheels lifecycle. This could enhance the LCFS credits' fungibility vis-à-vis other programs under AB 32. The proposed LCFS regulation does not set forth conditions on how those credits can be used in other AB 32 programs. This is because other AB 32 programs, when developed, presumably will specify their own conditions for imported credits (e.g., from the LCFS program).

On the other hand, staff proposes to prohibit the *import* of cap-and-trade allowances into the LCFS program. Tradable allowances generated under California regional cap-and-trade program requirements may be based on emissions reporting and compliance obligations different from that used in the LCFS. Thus, any importing of cap-and-trade allowances into the LCFS program would need to account for the differences in the two methodologies. To this end, some discounting or other adjustments may be needed in order to place LCFS credits and cap-and-trade allowances on an equal footing.

[46] A cap-and-trade program establishes an enforceable limit (or cap) on the aggregate total emissions for those entities covered by the program. The cap is set for each compliance period of the program by the State, and emission reductions increase as the cap declines over time.

Until regulatory provisions of a California cap-and-trade program are proposed(75)[47], staff believes it would be premature to include regulatory provisions for importing of cap-and-trade allowances into the LCFS program. As part of the rulemaking process on the California cap-and-trade program, staff will evaluate the feasibility of making cap-and-trade allowances and LCFS program credits interchangeable and, if appropriate, the conditions that should apply to such transactions.

ARB's Role in Credit Trading

Successful credit trading depends, in part, on what role ARB will play. In this regard, ARB can play a number of roles, each of which can have pros and cons, such as: (1) "hands off" regulator, (2) clearinghouse, and (3) trade facilitator.

Hands Off Regulator

As the term implies, a "hands off" role could have ARB serve no transactional role other than to issue LCFS credits, enforce the regulatory requirements, and track credit trades without publishing extensive information on such trades. This role has the benefit of imposing the least amount of administrative burden on both ARB and the regulated parties. Because of this, there would be fewer barriers to credit transactions, which presumably would help minimize transactional costs.

Among the downsides to this role would be a lower level of transparency in the credit market. The lack of such transparency can impede credit transactions because the regulated parties would have less information with regard to current market prices and market participants with available credits for sale.

Clearinghouse

As a clearinghouse, ARB could serve in both the enforcement role (noted in "Hands Off" above) and as a source of publicly available, credit-related information. Such information might include identification of regulated parties that have credits available for trades, the amounts of credits available, and the prices for such credits. This role would help fill in the transparency need noted above.

However, the need for transparency should be balanced with the need to avoid market manipulations that could be harmful to credit trading. For example, linking a specific regulated party with a specific amount of credits available may have an adverse effect a credit seller and buyer's negotiations. Similarly, a regulated party in need of credits may be placed in a disadvantageous position, depending on how much information is available from the clearinghouse (e.g., publication of credit balances). Further, confidential business information (e.g., sales volumes) might be gleaned from a clearinghouse if the data are not sufficiently delinked from the specific regulated parties.

[47] The AB 32 cap-and-trade rulemaking is tentatively scheduled for the Board's consideration in November 2010, with the launch of the California and WCI cap-and-trade programs scheduled for January 1, 2012.

Based on the above reasons, we believe careful consideration of these and other issues is warranted before designing any ARB clearinghouse for LCFS credits.

Trade Facilitator

This concept would take the clearinghouse role to the next level. In other words, ARB could serves as an intermediary between a credit seller and credit buyer, since ARB would have information on which parties have credits available and which need credits. This role has the advantage of helping to reduce transactional costs by providing the market with a known entity (ARB) that can connect sellers with buyers at little or no additional administrative cost. However, the benefits of reducing such transactional costs may be reduced if ARB cannot get buyers and sellers together more quickly or in effective numbers than a private, third-party facilitator, broker, agent, or similar entity can achieve.

<u>Summary</u>

It is clear that the above issues and concepts warrant a thorough evaluation in order to make the LCFS successfully integrate with the AB 32 cap-and-trade program. These and other cap-and-trade related issues will be investigated as staff develops the LCFS cap-and-trade related provisions in the short term.

L. Regulation Review

The Executive Officer will conduct a review of the implementation of the LCFS program by January 1, 2012. The review may cover areas impacting the design and enforcement of the LCFS regulation, such as the gasoline and diesel average carbon-intensity requirements; data and other information used for the carbon intensity lookup table and vehicle energy economy ratios; availability of biofuels and advanced vehicle technologies; and lifecycle and land-use change models, methods, and data. Special attention will be focused on indirect land use change. The review may also cover the logistics of complying with the LCFS such as the method, frequency, timelines of report submission, and the overall effectiveness and usability of the web-based Compliance and Reporting Tool. The exact scope and content of this review will be determined by the Executive Officer. Although not specified in the proposed regulation, staff intends to review the LCFS regulation approximately every three years after January 1, 2012.

VI. Compliance Scenarios

A. Summary

The LCFS is a performance-based standard: it neither mandates nor prohibits the use of specific fuels. Regulated fuel providers are free to make available any mix of fuels, so long as that mix complies with current carbon intensity limits. As such, a wide variety of compliance paths are possible. This Chapter describes seven such paths. Its goals are twofold: first, it demonstrates that compliance is possible, given what is currently known about the future availability of alternative fuels and vehicles; second, it shows that compliance is not contingent upon the availability of only a limited number of alternative fuel-vehicle combinations. The seven compliance paths described in this Chapter achieve these goals by demonstrating that compliance is possible under a wide range of fuel-vehicle scenarios.

Four of the scenarios described in this Chapter pertain to gasoline and fuels that can substitute for gasoline, and three pertain to diesel and its substitute fuels. Each scenario describes a compliance path involving a different combination of advanced renewable fuels, and advanced electric and hydrogen-powered vehicles.

Chapter IV also describes three supplemental scenarios. The first illustrated the effects of allowing light-duty diesel vehicles to earn compliance credits under the gasoline standard—a practice that is not permitted under the proposed Regulation. The second illustrates the extent to which compliance paths might be altered if no carbon intensity values included an indirect land use change component. The third supplemental scenario examines the carbon intensity reductions that could be expected if the LCFS were not implemented, but all Federal Renewable Fuel Standard production requirements were met in California.

The Chapter ends with a discussion of a likely compliance path for the decade following the current LCFS compliance year of 2020. Because the State's long-term climate change goals call for continued GHG reductions through 2050, it is probable that the LCFS will be renewed with revised post-2020 carbon intensity reduction requirements

B. Primary Scenarios

1. Establishing the Baseline

The LCFS baseline consists of baseline carbon intensity levels for gasoline and diesel, and a baseline year.

a. LCFS Baselines

ARB staff proposes that 2010 serve as the LCFS baseline year. In 2006, California reformulated gasoline contained an average of six percent ethanol by volume. As a result of the implementation of the Federal Energy Independence and Security Act of

2007 and California's reformulated gasoline regulations, the amount of ethanol in California reformulated gasoline is expected to increase to ten percent by volume.

The vast majority of ethanol used during the first three to five years of the LCFS is expected to be produced from corn. The carbon intensity of California reformulated gasoline (CaRFG) depends in part upon the carbon intensity of the ethanol with which it is blended. Because corn ethanol and California reformulated gasoline blendstock for oxygenate blending (CARBOB) have almost identical carbon intensities, the influence of the ethanol fraction on the carbon intensity of reformulated gasoline is insignificant.

Staff expects the carbon intensity of diesel fuel to remain essentially constant through the 2010 baseline year. Significant volumes of alternative blendstocks that would affect the carbon intensity of the baseline diesel fuel are not expected in the California Market by 2010.

b. Baseline Carbon Intensities of Gasoline and Diesel

The 2010 carbon intensities for gasoline and diesel were calculated using version 1.8b of the CA-modified GREET model.(47) The carbon intensity of gasoline is based on an assumed ethanol content of 10 percent by volume. Table VI-1 shows the assumed composition of average corn ethanol, as used in California reformulated gasoline. Twenty percent of the ethanol was assumed to come from the wet milling process, and 80 percent from the dry milling process. Of the dry milling process, 80 percent of the plants were assumed to dry their distiller's grain co-product, and 20 percent were assumed to sell their co-product as wet distiller's grain. Gasoline, including 10 percent ethanol by volume, has a carbon intensity of 95.85 gCO_2e/MJ. The carbon intensity of diesel in 2010 is estimated to be 94.71 gCO_2e/MJ. Details for both gasoline and diesel carbon intensity calculations can be found in the lifecycle analyses that are posted on the ARB website (http://www.arb.ca.gov/fuels/lcfs/lcfs.htm).

Table VI-1
Assumed Composition of the Ethanol Fraction of 2010 E10

<table>
<tr><td rowspan="4">E10</td><td rowspan="3">Ethanol: 10%</td><td rowspan="2">Dry Mill: 80%</td><td>Dry DGS, CI = 98.4: 80%</td></tr>
<tr><td>Wet DGS, CI = 90.1: 20%</td></tr>
<tr><td colspan="2">Wet Mill, CI = 105.10: 20%;</td></tr>
<tr><td>CARBOB: 90%</td><td colspan="2">CI = 95.86</td></tr>
</table>

2. Standards for 2020

To achieve a 10 percent reduction from 2010 levels, the standard for gasoline and fuels that substitute for gasoline will need to achieve a CI of 86.27 gCO_2e/MJ by the year 2020.

With a 10 percent reduction in the carbon intensity of diesel fuel, the carbon intensity of the diesel fool including the fuels that substitute for diesel will be 85.24 gCO_2e/MJ by 2020.

3. Compliance Schedules

Table VI-2 summarizes the proposed LCFS regulatory compliance schedules for gasoline and fuels that substitute for gasoline, and for diesel fuel and fuels that substitute for diesel fuel. These schedules apply to these fuels as they will exist in 2010, as well as to the various substitutes and blends that will become available over the compliance period. As Table VI-2 shows, implementation of the regulation begins in 2010.

Table VI-2
LCFS Compliance Schedules

Year	**CI for Gasoline and Fuels Substituting for Gasoline[1] (gCO_2e/MJ)**	**Gasoline and Fuels Substituting for Gasoline % Reduction**	**CI for Diesel and Fuels Substituting for Diesel (gCO_2e/MJ)**	**Diesel and Fuels Substituting for Diesel % Reduction**
2010	Reporting Only		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	86.27	10.0	85.24	10.0

[1]The use of 10.0 percent reduction is discussed in the baseline discussion found in the previous section.

The carbon intensity reductions shown in Table VI-2 are displayed graphically in Figures VI-1 and VI-2.

Figure VI-1

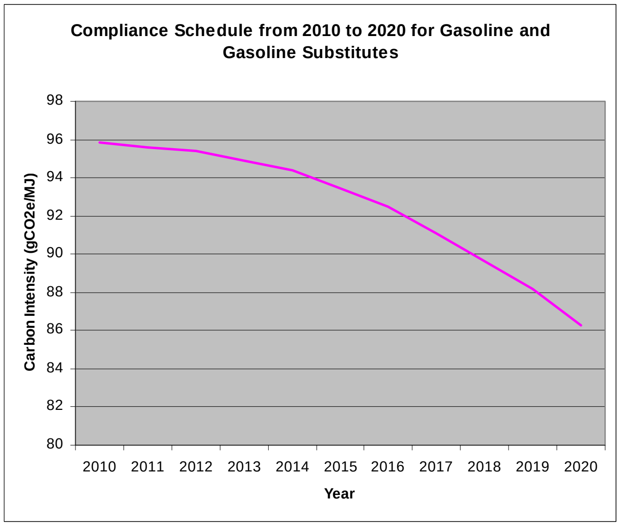
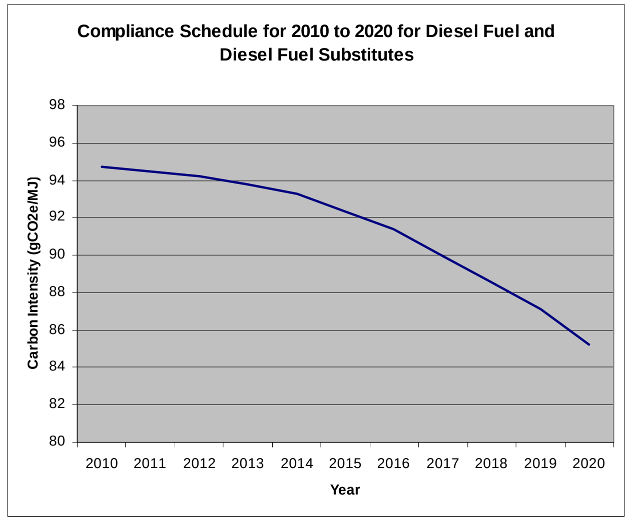


Figure VI-2



4. Compliance Scenarios

a. Introduction

The LCFS does not specify which combination of fuels the regulated parties must provide to comply with the standards. Instead, the LCFS requires producers and importers of transportation fuels to meet an overall carbon intensity for the fuel mix they supply to California. Regulated entities may meet the LCFS by using a combination of fuel blends, alternative fuels, and LCFS credits. Based on current and developing fuel and vehicle technologies, feedstock availabilities, and other factors, ARB staff has analyzed a number of possible compliance scenarios.

In this analysis, staff presents seven possible compliance scenarios—four for gasoline and its substitute fuels and three for diesel fuel and its substitute fuels. Each of these scenarios includes a mix of fuels that satisfy the LCFS. The purpose of describing compliance scenarios at this time is to demonstrate how the draft carbon intensity reductions are achievable, given prevailing and foreseeable future conditions. The compliance scenarios are not intended to predict or forecast the actual combination of fuels and vehicles that will be used.

The rate of future fuel and vehicle technological development is still uncertain. The technologies which currently appear to be most likely to produce marketable quantities of low-carbon fuels and vehicles to utilize those fuels over the near- to mid- term could encounter delays. The development of other, currently less well developed technologies, could achieve breakthroughs. Also, since the proposed regulation is performance based, fuel producers and importers can decide on how to achieve compliance. One or more of these outcomes could result in a set of compliance scenarios that is different from those described below.

b. Basis for Developing the Scenarios

The scenarios developed below are based on the following information and assumptions about fuel availability over the LCFS compliance period:

- Recent improvements in corn ethanol production processes have led to carbon intensity reductions for that fuel. In this analysis, these improvements are reflected in two additional types of improved corn ethanol: (1) Ethanol produced in the latest generation of California plants, which has a carbon intensity that is about 15 percent below that of CARBOB, and (2) Ethanol meeting the performance standard specified in the 2007 EISA: a 20 percent carbon intensity reduction over CARBOB. These fuels are referred to as California low-CI ethanol and Federal New Renewable Biofuels.
- For each gasoline-related scenario, the staff assumed that there was a baseline of approximately 300 million gallons of California low-CI ethanol available beginning in 2010 and that this volume would remain available in the California market through 2020.
- There are feedstocks available to produce sufficient quantities of cellulosic ethanol, advanced renewable ethanol, sugarcane ethanol, biodiesel, renewable diesel, and other renewable fuels, as necessary. These feedstocks include, but are not limited to cellulosic waste materials from agricultural, sugarcane, forestry wastes, municipal wastes, waste oils, and animal fats.
- Flexible fuel vehicles (FFVs) and/or advanced technology vehicles will be available in sufficient numbers to consume the quantities of E85, electricity, or hydrogen, assumed in each scenario. For ethanol, staff assumed that the gasoline blends consist of the maximum allowable 10 percent (E10) in the gasoline fleet and E85 in the FFV fleet.
- Each gasoline-related scenario includes a number of advanced technology vehicles that enable vehicle manufacturers to gain credits under the ARB's zero-emission vehicle program. These vehicles could be battery electric vehicles (BEVs), plug-in hybrid vehicles (PHEVs), or fuel cell vehicles (FCVs). For the purposes of this analysis, we have assumed that the percentage of vehicles in each class of these vehicles is the same as that projected for compliance with the 2008 ARB Zero Emission Vehicle (ZEV) regulation.
- The estimate of the carbon intensity of electricity is based on the California marginal electricity mix, where 79 percent of the electricity comes from highly efficient natural gas plants and 21 percent comes from renewable sources. Both electricity and hydrogen when used in advanced vehicles result in significant reductions in the carbon intensity of the fuel/vehicle system.

- The LCFS baseline for the gasoline and related fuels standard was projected based on the expected California fuel mix in 2010. The baseline gasoline blend is assumed to be E10. The number of light duty vehicle miles traveled is assumed to increase by 1.5 percent annually under the business as usual case. For this analysis, staff adjusted the amount of fuel consumed to reflect the implementation of ARB's GHG standards for light-duty vehicles, which results in a reduction of the total amount of E10 used in 2020 compared to 2010.
- The LCFS baseline for the diesel and related fuels standard was projected based on the expected California fuel mix in 2010. Staff assumed about a 2.2 percent annual increase in demand for diesel fuel between 2010 and 2020. This should be on the high side, as the diesel growth rate for the past two years has been negligible.
- For each scenario, staff assumes that there is no banking of credits. That is, all credits are used in the year that they are generated.

Tables VI-3 and VI-4 list the carbon intensities of the fuels used in the compliance scenarios developed below. These carbon intensities are derived from the carbon intensities presented in Chapter IV, "Determination of Carbon Intensity". Chapter IV presents a discussion of the basis for the carbon intensity values used in this report, including staff's current land use change impact estimates.

A very small portion of the diesel that will be available in 2010 will be blended with biodiesel. Biodiesel produced from waste fats and oils have no identified lifecycle emissions from indirect land use change impacts. Crop-based biodiesel, however, do have land use change impacts. Current estimates of these impacts appear in Chapter IV.

Table VI-3
Descriptions and Carbon Intensities of Fuels Included in the Compliance Scenarios for Gasoline and Fuels that Substitute for Gasoline

Gasoline, Gasoline Blendstock, or Replacement	Pathway Description	Carbon Intensity (grams CO_2e/MJ)			Status	
		Direct Emissions	Land Use or Other Effect	Total	Proposed for Adoption	Under Development
CARBOB	CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies	95.86	0	95.86	X	
CaRFG – 2010 Baseline Fuel	CaRFG - CARBOB and a blend of 80% Midwestern corn ethanol and 20% California corn ethanol to 10% ethanol	95.85	---	95.85 [1]	X	
Midwestern Average Corn Ethanol	Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	69.40	30	99.40	X	
California Low CI Ethanol	California; Dry Mill; Wet DGS; NG	50.70	30	80.70	X	
Cellulosic Ethanol	Farmed poplar trees using a fermentation process	2.40	18.00	20.40		X
Advanced Renewable Ethanol	Forest waste	22.20	0	22.20		X
Sugarcane Ethanol	Brazilian sugarcane using average production processes	27.40	46	73.40	X	
Federal New Renewable Biofuels	20% reduction in the carbon intensity of CARBOB	76.69	---	76.69 [1]		X
Federal Cellulosic Biofuels	60% reduction in the carbon intensity of CARBOB	38.34	---	38.34 [1]		X
Federal Advanced Biofuels	50% reduction in the carbon intensity of CARBOB	47.93	---	47.93 [1]		X
Electricity	California marginal electricity mix of natural gas and renewable energy	104.70	0	34.90 [2]	X	
Hydrogen	SB 1505 Scenario; gaseous hydrogen from on-site reforming with renewable feedstocks	76.10	0	33.09 [3]	X	

[1] Calculated value; land use assumed to be part of the value
[2] Adjusted for by an Energy Economy Ratio of 3.0 to account for differences in power train efficiency of electric vehicles and plug-in electric vehicles over gasoline-powered vehicles
[3] Adjusted for by an Energy Economy Ratio of 2.3 to account for differences in power train efficiency of fuel cell vehicles over gasoline-powered vehicles

Table VI-4
Descriptions and Carbon Intensities of Fuels Included in the Compliance Scenarios for Diesel and Fuels that Substitute for Diesel

Diesel, Diesel Blendstock, or Replacement	Pathway Description	Carbon Intensity (grams CO_2e/MJ)			Status	
		Direct Emissions	Land Use or Other Effect	Total	Proposed for Adoption	Under Development
ULSD Diesel – 2010 Baseline	ULSD – based on the average crude oil delivered to California refineries and average California refinery efficiencies	94.71	0	94.71	X	
Biodiesel-Soybeans	Midwest soybeans to soy oil (Fatty acid methyl esters-FAME) for conversion to biodiesel	26.93	42	68.93 [1]	X	
Biodiesel or Renewable Diesel – Waste-Derived	Tallow conversion using co-fed stream into refinery or bio-refinery, or yellow grease, fats, and waste oils for conversion to biodiesel or renewable diesel	15.00	0	15.00 [1]	X	
Compressed Natural Gas	North American natural gas delivered via pipeline; compressed in California	68.00	0	75.56 [1]	X	
Federal Biomass-Based Diesel	50% reduction in the carbon intensity of ULSD Diesel	47.36	---	47.36 [2]		X
Electricity	California marginal electricity mix of natural gas and renewable energy	104.70	0	38.78 [3]	X	

[1] Preliminary estimate
[2] Calculated value; land use assumed to be part of the value
[3] Adjusted for by an Energy Economy Ratio of 2.70 to account for differences in power train efficiency of electric vehicles and plug-in electric vehicles over diesel-powered heavy-duty vehicles

The renewable fuel requirements of the Energy Independence and Security Act of 2007 (EISA) set federal mandates for the development of low carbon fuels. EISA increased the amount of renewable fuels that gasoline and diesel fuels must contain under the U.S. EPA's Renewable Fuels Standard previously established in 2005. In 2008, 9 billion gallons of renewable fuel must be used, increasing to 36 billion gallons per year by 2022. In 2010, EISA requires that 0.95 billion gallons of federal advanced biofuel and 0.1 billion gallons of federal cellulosic biofuel be used, while in 2022, these requirements increase to 21 billion gallons and 16.0 gallons. These requirements are shown in further detail in Chapter II: Table II-3. In effect, EISA established minimum renewable fuel production levels and carbon reduction performance metrics at the national level.

The difference between total advanced biofuels and total renewable fuel is allowed to be ethanol from corn with up to 13 billion gallons of conventional corn to ethanol and about 2 billion gallons Federal New Renewable Biofuels corn to ethanol that has a CI 20% less than base gasoline.

c. Compliance Scenarios for Gasoline and Gasoline Substitutes

The purpose of the scenarios was to estimate the amounts of low-carbon gasoline and diesel fuel substitutes, and the number of FFVs and advanced vehicles, that would be needed in future years to meet the proposed carbon intensity values of the LCFS. The starting point for these estimates was to estimate the total amount of both on-road and off-road transportation fuels that would be used in California in future years. The basis of these estimates was the ARB's EMFAC motor vehicle emissions model, data on taxable sales of motor vehicles fuels in California, published by the State Board of Equalization (BOE), and data on fuels production published by the U.S. Department of Energy Information Administration (EIA). On-road motor vehicle fuel use was estimated by using EMFAC estimates of vehicle miles traveled for the year 2008, and by incorporating assumptions on fuel economy that resulted in fuel use estimates consistent with the State Board of Equalization's estimate of taxable on-road fuel use. Off-road diesel fuel use was estimated so that total diesel fuel use would be consistent with the EIA's estimate of total fuel use in California for 2008.

Estimates of fuel use in future years were made by applying to the 2008 estimates assumed annual VMT growth rates of about 1.5 percent for gasoline motor vehicles, and about 2.2 percent for heavy-duty diesel vehicles. In estimating fuel use in future years, the staff also accounted for measures that result in a decrease in the amount of motor vehicle fuel used. These measures are listed below:

- The regulations (both adopted and planned) by the ARB pursuant to requirements of AB 1493 (Pavley) which have the result of increasing the fleet-wide fuel average fuel economy of gasoline motor vehicles by about 24 percent (the equivalent of about 31.7 MMT/yr of greenhouse gases) in 2020;

- The effects of the implementation of regional transportation-related GHG targets, required by SB 375, which will reduce fuel use by an amount equivalent to about 5 MMT/yr of greenhouse gases;
- The effects of measures being considered and proposed by the ARB to increase vehicle efficiency, such as the rule to maintain adequate tire pressure, which will reduce fuel consumption by an amount equivalent to abut 4.5 MMT/yr of greenhouse gases;
- The effects of measures to be adopted by the ARB which will increase the aerodynamic efficiency of heavy-duty vehicles, and which will reduce fuel use by an amount equivalent to about 1.4 MMT/yr of greenhouse gases;
- The use of about 560,000 advanced technology (BEV, PHEV, and FC) vehicles in 2020 required under the Zero Emission Vehicle Regulations adopted by the ARB; and
- The use of about 500,000 light and medium-duty diesel vehicles in 2020, which results in a slight shift in fuel use from gasoline to diesel.

Table VI-5 lists the measures that will significantly decrease the amount of fuel used in the future along with their corresponding CO_2E emission reductions.

From the total amount of fuel estimated to be used in future years, a total energy demand was estimated. Using the total energy demand and the carbon intensities of gasoline, diesel, and gasoline and diesel fuel substitutes, the total amounts of lower carbon intensity gasoline and diesel fuel substitutes were estimated.

Table VI-5
Measures to Reduce GHG Emissions

Measure	Description	Emission Reductions Counted Towards 2020 Target ($MMTCO_2E$)
California Light-Duty Vehicle Standards	Implement adopted Pavley standard and planned second phase of the program. Align zero-emission vehicle, alternative and renewable fuel and vehicle technology program with climate change goals.	31.7
Regional Transportation-Related GHG Targets	Develop regional GHG emissions reduction targets for passenger vehicles pursuant to Senate Bill 375.	5
Vehicle Efficiency Measures	Implement light-duty vehicle efficiency measures including properly inflated tires, consideration of minimum fuel-efficient tire standards, and reducing engine load via lower friction oil and reducing the need for air conditioner use.	4.5
Medium/Heavy Duty Vehicles	Adopt medium and heavy-duty vehicle efficiency measure including retrofits to improve the fuel efficiency of heavy-duty trucks by reducing aerodynamic drag and rolling resistance and hybridization of medium-and heavy-duty vehicles.	1.4

Staff developed four compliance scenarios for gasoline and gasoline substitutes. These scenarios differ in the volumes of corn-based ethanol, cellulosic ethanol, sugarcane ethanol, and advanced renewable ethanol. The number of FFVs assumed to be using E85 and the number of advanced vehicles (BEV, PHEV, FCV) using electricity or hydrogen also change significantly in several scenarios.

In general, the four scenarios can be characterized as follows:

> Scenario 1: Increasing volumes of Federal New Renewable Biofuels (ethanol)(10)[48] through 2015, then gradual decline of higher CI crop-based biofuels through 2020 as advanced renewable ethanol fuels become available. Conventional corn ethanol gradually decreases to zero in 2017, but lower intensity corn ethanol remains. There would be gradual increases in the number of FFVs using E85. The number of advanced technology vehicles (BEV, PHEV, FCVs) using electricity or hydrogen as a fuel increases to about 560,000 by 2020. This number is consistent with the penetration schedule in the 2008 ARB ZEV regulation.
>
> Scenario 2: Similar to Scenario 1 except that a wider mix for cellulosic ethanol, advanced renewable ethanol, and sugarcane ethanol is used.
>
> Scenario 3: Similar to Scenario 2 except that the number of advanced technology vehicles is increased from 560,000 vehicles to 1 million vehicles in 2020. In turn, the number of FFVs using E85 in 2020 and the amount of cellulosic ethanol, advanced renewable ethanol, and sugarcane ethanol are reduced.
>
> Scenario 4: Similar to Scenario 3 except the number of advanced technology vehicles is increased to 2 million vehicles in 2020 and biofuel amounts are reduced.

The year-by year assumptions used in each scenario are presented in Appendix E. In general, the LCFS can be met through about 2015 with a combination of somewhat lower-carbon corn derived ethanol or through the use of ethanol from sugarcane. For these years, almost all of the needed biofuels can be used in E10 and very little E85 is needed. However, as the LCFS (and concurrently the federal RFS) become increasingly more stringent, the scenarios transition to higher volumes of very low carbon ethanol, with higher numbers of FFVs using E85, and higher numbers of advanced vehicles. In all cases, once a specified volume of lower-carbon biofuel is produced, that volume is maintained throughout 2020. In addition, the scenarios retain

[48] The Federal Renewable Fuels Standard (RFS2), which is discussed in Chapter II of this report) specifies that ethanol derived from corn starch produced at new facilities that commence construction after the date the act was signed, must achieve at least a 20 percent reduction in lifecycle greenhouse gas emissions compared to baseline lifecycle greenhouse gas emissions. The baseline is defined as the average 2005 lifecycle GHG emissions for gasoline.

about 300 million gallons of lower-carbon intensity ethanol from corn expected to be produced at existing or planned California ethanol production facilities.

The results for 2020 are summarized in Tables VI-6, VI-7, and VI-8. Table VI-6 presents a summary of the amount of fuel used in 2020 for biofuels, electricity, and hydrogen. Table VI-7 presents a breakdown of the types of ethanol used for each scenario in 2020. Table VI-7 also shows the amount of ethanol used as a percent of the total amount of E85 and E10 and the amount of ethanol used as a percent of gasoline. For each gasoline-related scenario, Table VI-8 shows the percent contribution that each fuel type plays in reducing GHG emissions as part of the LCFS for gasoline in 2020.

Table VI-6
Summary of Fuels and Vehicles Used in Each Scenario to Meet the 2020 Standard for Gasoline and Fuels that Substitute for Gasoline*

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Volume of Ethanol (Million Gallons)	2.9	3.1	2.8	2.2
Total Amount of Electricity (Gigawatt Hours)	1,210	1,210	2,240	4,470
Total Amount of Hydrogen (Megagrams)	10,500	10,500	16,500	33,000
Number of Advanced Vehicles (Battery Electric, Plug-in Electric, and Fuel Cell Vehicles) (Million of Vehicles)	0.56	0.56	1.0	2.0
Number of Flexible Fuel Vehicles Operating on E85 (Millions)	3.0	3.4	2.9	1.8

* Numbers are rounded.
[1] Baseline gasoline consists of 90% CARBOB and 10% Ethanol by volume.

Table VI-7
Summary of Ethanol Use in the Various Scenarios for Fuels that Substitute for Gasoline in 2020

Ethanol	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Midwestern Average Corn Ethanol (Millions of Gallons)	300	0	0	0
California Low CI Ethanol (Millions of Gallons)	0	300	300	300
Cellulosic Ethanol (Million Gallons)	1,290	1,240	1,100	790
Advanced Renewable Ethanol (Million Gallons)	1,290	1,240	1,100	790
Sugarcane Ethanol (Million Gallons)	0	300	300	300
Total Volume of Ethanol (Million Gallons)	2,880	3,080	2,800	2,180
Overall Percent of Ethanol in Gasoline	19.6	20.2	19.3	15.7
Volume of E85 (Million Gallons)	1,980	2,250	1,920	1,190

[1] 2010 starting-year gasoline consists of 90% CARBOB and 10% Ethanol by volume.

Table VI-8
Contribution to Reducing GHG Emissions in the LCFS For Fuels Substituting for Gasoline Fuel in 2020

Fuel Type	Percent of Reductions Provided by Each Fuel Type Substituting for Gasoline in 2020[1]			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CA Low-CI Ethanol	2	2	2	2
Cellulosic Ethanol	44	43	38	28
Advanced Renewable Ethanol	43	41	36	27
Sugarcane Ethanol	0	3	3	3
Electricity	9	9	18	35
Hydrogen	2	2	3	5

[1] Baseline gasoline consists of 90% CARBOB and 10% Ethanol by volume.

d. Compliance Scenarios for Diesel Fuel and Substitutes for Diesel Fuel

Staff developed three possible compliance scenarios for the diesel fuel group as summarized below:

<u>Scenario 1</u>: The first scenario is based on a diversification of the liquid fuel pool using available low-carbon-intensity fuels.

<u>Scenario 2</u>: The second scenario includes not only a variety of liquid fuels, but also significant numbers of CNG vehicles penetrating the fleet.

<u>Scenario 3</u>: The third scenario increases the compliance options by expanding Diesel Scenario 2 to include additional advanced technology vehicles, including PHEVs used to replace conventional diesel vehicles.

The three scenarios require the availability of two categories of non-petroleum diesel:

- Biomass-based diesel includes the following:
  - Conventional biodiesel, made from oil derived from crops using the fatty acid to methyl ester (FAME) process. Conventional biodiesel has a carbon intensity of 68.93 gCO_2 e/MJ.
- Advanced renewable diesel is a fuel made from non-crop-based feedstocks. These include wood waste, municipal wastes, algae, waste oils and fats from animals processed to meats. These fuels do not have a land use change impact. These waste-derived biodiesel/renewable diesels were assumed to have carbon intensities of 15 gCO2e/MJ.

The year-by year summaries are presented in Appendix E. In general, as the penetration of CNG vehicles and advanced technology vehicles increases, the need for biodiesel and advanced renewable biodiesel decreases. The increased vehicle penetration also reduces the amount of biodiesel and advanced renewable biodiesel needed for blending into conventional diesel. Even in Scenario 1, where liquid fuels are providing all of the necessary reductions, the amount of alternative fuels needed for blending is less than 20%.

The results for 2020 are summarized in Tables VI-9, VI-10, and VI-11. Table VI-9 presents a summary of the amount of fuel used in 2020 for biofuels, electricity, and natural gas. Table VI-9 also shows the amount of biodiesel and advanced renewable biodiesel used as a percent of the total amount of diesel. Table VI-10 presents a breakdown of the types of biodiesel and advanced renewable biodiesel used for each scenario in 2020. For each diesel-related scenario, Table VI-11 shows the percent contribution that each fuel makes to reduce the deficits that result from a business as usual case of using conventional diesel in 2020.

Table VI-9
Contribution to Reducing GHG Emissions in the LCFS for Diesel Fuel and Fuels that Substitute for Diesel Fuel*

	Scenario 1	Scenario 2	Scenario 3
CNG (mmscf)	0	14,210	17,050
Total Amount of Electricity (Gigawatt Hours)	0	0	387
Number of CNG Vehicles	0	20,900	25,100
Number of PHEV Vehicles	0	0	8,367
Volume of Biodiesel and Advanced Renewable Diesel (Million Gallons)	838	822	788
Overall Percent of Biodiesel and Advanced Renewable Diesel in Conventional Diesel	15.4	15.4	14.9

* Numbers have been rounded.

Table VI-10
Summary of Biofuel Use in the Various Scenarios for Fuels that Substitute for Diesel Fuel*

Potential Fuels	Summary of Biofuel Volumes Used in 2020 For Each Scenario		
	Scenario 1	Scenario 2	Scenario 3
Conventional Biodiesel (Million Gallons)	4,607	4,530	4,517
Advanced Renewable Biodiesel (Million Gallons)	281	276	264
Volume of Biodiesel and Advanced Renewable Diesel (Million Gallons)	557	546	524

* Numbers have been rounded.

Table VI-11
Contribution to Reducing the Deficits for Fuels Substituting for Diesel Fuel in 2020

Potential Fuels	Percent of Reductions Provided by Each Fuel Type Substituting for Diesel in 2020		
	Scenario 1	Scenario 2	Scenario 3
CNG	0	2	2
Electricity	0	0	3
Conventional Biodiesel	14	14	13
Advanced Renewable Biodiesel	86	84	81

C. Supplemental Scenarios

1. Light-Duty Diesel Credit Scenario

The Low Carbon Fuel Standard (LCFS) specifies two carbon intensity levels, one for gasoline and its substitute fuels, a second for diesel and its substitutes. Gasoline and fuels used as substitutes for gasoline must meet a carbon intensity target of 86.27 gCO_2e/MJ by 2020, while the corresponding target for diesel and fuels used as substitutes for diesel is 85.24 gCO_2e/MJ.

For the most part in the proposed LCFS, fuels used in light duty passenger vehicles and trucks are measured against the gasoline standard, the fuel used by the overwhelming majority of these vehicles. However, this does not apply for the small portion (about 1 percent) of the current light duty fleet that uses diesel fuel. A number of parties have urged ARB to allow diesel fuel to be used to earn LCFS compliance credits against the gasoline compliance standards when it is used in light-duty vehicles[49]. If permitted to comply with the gasoline standards in the LCFS, suppliers of fuels to light-duty diesel vehicles could earn credits under the gasoline standard.

Achieving even this modest contribution toward the 2020 LCFS gasoline standard, however, would require the California light-duty diesel fleet to grow to one million vehicles by 2020[50]. An increase of this magnitude appears to be unlikely. As Table VI-12 shows, light- and medium-duty diesel vehicles have not gained significant acceptance with California consumers.

Table VI-12
Composition of the 2008 California Vehicle Fleet*

	Diesel-Powered	Total Fleet	Diesel Percentage
Passenger Vehicles	49,150	13,000,000	0.4%
Light-Duty trucks weighing <= 3,750 lbs	156,400	2,800,000	5.6%
Light-Duty trucks weighing > 3,750 lbs	16,580	5,400,000	0.3%
Medium Duty Vehicles	11,100	2,400,000	0.5%

Source: Emfac 2007 v2.3 (November 1, 2006)

* Numbers have been rounded.

There have not been many diesel passenger cars and diesel light-duty trucks certified in California in recent years. More medium-duty diesel truck models have been California-

[49] Because the compression-ignited diesel engine cycle is more efficient than the spark-ignited gasoline engine cycle, diesel vehicles have lower GHG exhaust emissions than comparable gasoline-powered vehicles. As a result of this efficiency advantage, diesel-powered vehicles are currently between 15 and 20 percent lower emitting on a per mile travelled basis than their gasoline powered counterparts.

[50] Diesel fleet estimates are from tax data supplied to the California Bureau of Equalization

certified. Despite this availability, they continue to comprise under 0.5 percent of the medium-duty vehicle fleet. Additional factors likely to influence the size of the future vehicle fleet are:

- The increasing efficiency of gasoline vehicles will continue to close the efficiency gap separating gasoline from diesel vehicles; and
- The price of diesel fuel may not drop significantly below the price of gasoline.

If the assumption is made that one million light duty vehicles will enter the fleet by 2020, these one million light-duty diesel vehicles running on fuel that complied with the 2020 LCFS carbon intensity standard of 85.24 gCO_2e/MJ would emit 3.9 million metric tons of CO_2 per year. The difference between that and the comparable gasoline-powered vehicle emission level of 4.7 million metric tons would yield the number of credits generated, about 0.8 million metric tons per year.

One million diesel vehicles running on fuel which met the 2010 baseline fuel carbon standard of 94.71 gCO_2e/MJ would emit higher volumes of CO_2: 4.3 million metric tons per year. The credit earned by these vehicles would be the difference between this emission rate, and the corresponding emission rate for the same number of gasoline vehicles, about 0.4 million metric tons per year.

Table VI-13 puts these light duty diesel credit figures into perspective by comparing them with the credits that would be earned by various other fuel-vehicle combinations. Although the 0.8 credits that would be earned by diesel vehicles that comply with the 2020 standard would be significant, it is well below the number of credits that the two electric vehicle classifications would earn, and only half of what hydrogen fuel cell vehicles would earn. Also, as noted, it ignores the improvements in the gasoline engine technology that would close the gap in engine efficiencies and eliminate most, if not all, of the credits.

Table VI-13
Comparison of LDV Diesel Credits Scenario with Comparable Scenarios for Other Vehicle-Fuel Combinations (All Comparisons Based on 1,000,000 vehicles)

Fuel-Vehicle Combination	Credits Earned (MMT/yr CO2)
LDV/MDV Diesel Vehicles Meeting 2020 Std.	0.8
LDV/MDV Diesel Vehicles Meeting Baseline Std.	0.4
FFVs Using E85 containing 100% Advanced Renewable Ethanol	0*
Battery Electric Vehicles	2.8
Plug-in Hybrid Vehicles	2.1
Fuel Cell Vehicles	2.9

*E85 earns no LCFS credits because it is used in vehicles with an Energy Efficiency Rating of 1 (equivalent to standard gasoline-powered vehicles).

2. No Indirect land-Use Change Scenario

The carbon intensities of the crop-based biofuels used in the gasoline scenarios 1 through 4 (see Section VI-4c, above) include an indirect land use change component, which ranges from zero for advanced renewable ethanol to 46 gCO_2e/MJ for sugarcane ethanol, as shown in Table VI-3. The supplemental scenarios developed in this section demonstrate the effects of removing that increment from the gasoline scenarios and contain no indirect land use change increment.

Reducing the carbon intensities of crop-based ethanols by the amount of the indirect land use change increment has two effects on the four gasoline compliance scenarios. The first is to lower the carbon intensity of baseline gasoline from 95.85 to 93.39. This reduction results from a reduction in the average carbon intensity of corn ethanol in baseline gasoline from 95.7 to 65.7, and the assumption that the baseline gasoline contains 10 percent (by volume) corn ethanol. The second effect of excluding the indirect land use effect is to reduce the average carbon intensity of gasoline that will be used to meet LCFS carbon intensity reduction requirements. However, the reduction in the carbon intensity of the complying gasoline is not the same for all scenarios. This variability results from the fact that the magnitude of the land use effect varies by ethanol type, and the fact that different scenarios call for different proportions of ethanol types.

As shown in Table VI-3, the land use effect ranges from 46 for sugar cane ethanol to 30 for midwestern average corn ethanol and California low-carbon intensity ethanol, to 18 for cellulosic ethanol, and to zero for advanced renewable ethanol. The proportion of total carbon intensity attributable to indirect land use change varies from 63 percent for sugar cane ethanol to zero percent for advanced renewable ethanol. As a result, the effect of excluding the land use component from ethanol carbon intensities will vary with scenario, due to the relative amounts of each ethanol type assumed under each scenario.

Table VI-14 shows the variable effects on 2020 gasoline carbon intensities of excluding indirect land use change effects from the carbon intensity ratings of ethanol. The carbon intensities shown include the reduction in carbon intensity resulting from the number of plug-in hybrid electric vehicles, battery electric vehicles, and fuel cell vehicles called for under each scenario.

Table VI-14
Effect of Excluding Land Use Emissions on Gasoline Carbon Intensity in Year 2020

Scenario	Baseline AFCI (gCO_2e/MJ)	2020 Average AFCI (gCO_2e/MJ)	% Reduction
Scenario 1	93.39	84.2	9.8
Scenario 2	93.39	83.6	10.5
Scenario 3	93.39	83.7	10.4
Scenario 4	93.39	84.0	10.1

The above table shows that the exclusion of the indirect land use component from the carbon intensities of the various types of fuels used to achieve a 10 percent reduction in the gasoline carbon intensity in 2020 has very little effect on the percent reduction in carbon intensity achieved in 2020. The percent reduction in carbon intensity remains very close to 10 percent after the indirect land use component is excluded. Therefore, the amounts of the various fuels needed in 2020 to achieve a 10 percent reduction in carbon intensity change very little. This is illustrated in the table below, which compares the number of FFVs and the amounts of the fuels needed to be used to achieve a 10 percent reduction in carbon intensity if the indirect land use components are included, to the number of FFVs and the amounts of fuels that would be needed in 2020 if the indirect land use components are excluded.

Table VI-15
Effect of Excluding Indirect Land Use Effects on the Amounts of EtOH Blendstocks Needed to Achieve 10 Percent Reduction in Carbon Intensity in 2020 (Billions of Gallons)

	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	With ILUC	Without ILUC	With ILUC	Without ILUC	With ILUC	Without ILUC	With ILUC	Without ILUC
MW Avg.Conv. Corn EtOH	0	0	0	0	0	0	0	0
CA Low CI Corn EtOH	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Cellulosic EtOH	1.29	1.32	1.24	1.19	1.10	1.06	0.79	0.77
Adv. Renew. EtOH	1.29	1.32	1.24	1.19	1.10	1.06	0.79	0.77
Sugar Cane EtOH	0	0	0.30	0.30	0.30	0.30	0.30	0.30
No. of FFVs (millions)	3.0	3.1	3.4	3.2	2.9	2.73	1.8	1.7

The table above shows that, in Scenarios 2, 3, and 4, the 10 percent reduction in carbon intensity can be achieved in 2020 with slightly less volumes of cellulosic ethanol and advanced renewable ethanol if the indirect land use component of carbon intensity is excluded. It should be noted that in Scenario 1 more cellulosic ethanol and advanced renewable ethanol is needed if the indirect land use component of carbon intensity is excluded. This is due to the need to achieve a 10% reduction in CI from a lower number.

It is important, however, to include the indirect land use component in the LCFS to account for significant effects and to ensure that the market signals are correct.

3. Federal "RFS Only" Scenario

A reduction in the average carbon intensity of California fuels would be expected from the implementation of the federal Energy Independence and Security Act of 2007 (EISA) even in the absence of a California LCFS. This section provides an estimate of the benefits of the federal program alone.

EISA requires that of 30 billion gallons of renewable fuel be produced nationwide in 2020. Of these 30 billion gallons, up to 15 billion gallons of corn derived biofuel is allowed and 10.5 billion gallons of cellulosic biofuel and 4.5 billion gallons of other advanced biofuel and are required. If California were to receive 11.3 percent of the renewable fuels required under EISA, the California gasoline pool would receive in 2020 about 1.19 billion gallons of cellulosic biofuel (ethanol) designated under the Act to have a 60 percent reduction in carbon intensity and about 340 million gallons of advanced biofuel designated by the Act to have a 50 percent reduction in carbon intensity. The use of these volumes of cellulosic and advanced biofuel, in combination with 1.17 billion gallons of mid-west corn ethanol and 300 million gallons of lower-carbon intensity corn ethanol from California dry mill facilities with wet distiller grain solubles (DGS), would reduce the average carbon intensity of California gasoline by about 4 percent.

Under EISA, about 100 million gallons of biomass-based diesel fuel designated by the Act to have a 50 percent reduction in carbon intensity would be used in the California diesel pool in 2020. The use of this biomass-based diesel fuel would achieve about a one percent reduction in the carbon intensity of California diesel fuel in 2020. Overall, compliance with EISA would achieve about a three percent reduction in emissions and the carbon intensity of the combined California gasoline and diesel fuel pool in 2020. This translates into an emissions reduction of 7.3 million metric tons per year of greenhouse instead of about 23 million metric ton per year from implementation of the LCFS.

Additional details are provided in Appendix E.

D. Fuel Carbon Reductions in the Post-2020 Period

Fuel carbon intensity reductions beyond those required under the LCFS in 2020 will be needed to meet the greenhouse gas emission reduction goals beyond the 2020 target set pursuant to AB32. The LCFS will need to be periodically revisited and updated. Staff anticipates that a major revision would be needed in the 2015 timeframe to establish the appropriate LCFS annual standards for the 2021 through 2030 timeframe. This effort will draw upon the real world progress that is made over the next five years in the development of very low carbon fuels and the deployments of highly efficient vehicles capably of operating on advanced fuels.

It is vital that fuel suppliers look beyond 2020 in their assessments of the types and quantities of transportation fuels that might be used in California over the next 20 years. The 2030 Scenario presents an assessment of what that future might be, and provides estimates of how the lower carbon intensity fuels might be deployed to achieve very significant greenhouse gas reductions by 2030. The scenario for gasoline is shown in Table VI-16, while the assumptions for the 2030 diesel scenario are shown in Table VI-17.

Table VI-16
2030 Gasoline Scenario Assumptions

Total Number of LD/MD Vehicles (millions)	36.0
Total Number of LD/MD FFVs (millions)	4.5
Total Number of LD/MD PHEVs (millions)	3.6
Total Number of LD/MD FCVs (millions)	1.8
Total Number of LD/MD BEVs (millions)	1.8
Total Number of LD/MD Diesels (millions)	2.5
Carbon Intensity of Electricity (gCO2e/MJ)	90.0
Carbon Intensity of Hydrogen (gCO2e/MJ)	76.1
Carbon Intensity of CA Low-Carbon Intensity Corn EtOH (gCO2e/MJ)	80.7
Carbon Intensity of Cellulosic EtOH (gCO2e/MJ)	20.4
Carbon Intensity of Advanced Renewable EtOH (gCO2e/MJ)	22.2
Carbon Intensity of Sugar Cane EtOH (gCO2e/MJ)	73.40
Amount of CA Low-AFCI Corn EtOH Used (billion gal/year)	0.34
Amount of Cellulosic EtOH Used (billion gal/year)	1.25
Amount of Advanced Renewable EtOH Used (billion gal/year)	1.25
Amount of Sugar Cane EtOH Used (billion gal/year)	0.34

Table VI-17
2030 Diesel Scenario Assumptions

Percent of HD Vehicles are PHEVs (percent)	10
Percent of HD Vehicles are CNG (percent)	10
Carbon Intensity of Electricity (gCO2e/MJ)	90.0
Carbon Intensity of CNG (gCO2e/MJ)	75.56
Carbon Intensity of Conventional Biodiesel (gCO2e/MJ)	68.93
Carbon Intensity of Advanced Renewable Diesel (gCO2e/MJ)	15.00
Amount of Conventional Biodiesel Used (million gal/year)	250
Amount of Advanced Renewable Diesel Used (million gal/year)	1,000

On the basis of the assumptions in Tables VI-16 and VI-17, the average carbon intensity of gasoline would be reduced by about 25 percent, while the average carbon intensity of diesel would be reduced by about 17 percent in 2030. The greenhouse gas emissions reductions would be about 49 million metric tons per year (CO2 equivalent) in 2030 compared to the estimated 23 million metric tons in 2020.

VII. Environmental Impacts

This Chapter presents the environmental benefits and impacts that are associated with meeting the LCFS. The LCFS is a performance-based standard. Consequently, the specific pathways chosen by fuel producers to comply with the LCFS are uncertain. However, the GHG benefits (addressed on Section B of this chapter) can be estimated based on the projected energy requirements needed over time. In addition, potential air quality impacts can be evaluated based on various compliance scenarios. As part of the air quality analysis (as addressed in Section C of this chapter), the staff has estimated the emissions that could result from the production, distribution, and use of alternative fuels in California, evaluated potential mitigation options, and estimated the public health risks associated with individual and multiple co-located biofuel production facilities.

In addition to the GHG emission benefits and air quality analyses, the staff has evaluated other potential environmental impacts (addressed in Section D of this Chapter). These include potential impacts on water; aesthetics; agricultural, biological and cultural resources; geology and soils; hazards and hazardous materials; mineral resources; housing and population; public services; recreation; solid waste; and transportation and traffic.

The last three sections of this Chapter address staff's approach to addressing the long term sustainable production of low carbon fuels, the multimedia analysis, and the environmental justice implications of the LCFS.

Appendix F presents supporting information for this Chapter.

A. Summary of the Environmental Analysis

The environmental analysis of the proposed LCFS regulation focuses on significant decreases in the GHG emissions that would result from the proposed regulation. These reductions would result from production and use of lower carbon transportation fuels in California and changes in the vehicle fleet composition due to new, lower carbon fuels being available to the transportation fuel pool. Staff has estimated the GHG emissions reductions for the combustion of transportation fuels to be about 16 MMT CO_2e by 2020. Staff has also estimated GHG reductions for the full fuel lifecycle, including fuel production through combustion, of 23 MMT CO_2e in 2020. These reductions account for a 10 percent reduction of the GHG emissions from the use of transportation fuel. These reductions compare to the expected 3 percent reduction in GHG emissions if only the federal RFS 2 requirements were met.

The proposed LCFS regulation is also expected to result in no additional adverse impacts to California's air quality due to emissions of criteria and toxic air pollutants. Based on the best available data, there may be a benefit in further reducing criteria air pollutants from the 2020 projected vehicle fleet.

To meet the proposed LCFS and the federal RFS 2, new biofuel production facilities will likely be built in California. Staff estimates a total of thirty facilities producing corn ethanol (6), cellulosic ethanol (18), and biodiesel (6) could be operational by 2020 based on an assessment of the availability of feedstock material. Biofuel production on a commercial scale will require development of new technologies as well as the continued use of conventional technology with crop-derived feedstocks. Non-crop feedstocks could include biomass wastes from municipal solid wastes, agriculture wastes, waste oils, and forestry. Criteria pollutant emissions were estimated for the production of biofuels, the collection of feedstock, and delivery of the finished biofuel.

The emissions estimated for the biofuel production facilities reflect the use of the cleanest energy conversion technologies and air pollution control technologies. ARB staff recommends that the emissions associated with the production of low carbon fuels be fully mitigated consistent with local district and CEQA requirements.

For cellulosic ethanol facilities, the energy requirements are typically greater than that for conventional ethanol facilities based on the conversion of corn starch. To provide additional information for local districts and to inform the CEQA process, ARB staff is committed to developing a guidance document to provide information on the best practices available to reduce emissions from these types of facilities. This effort will commence immediately; ARB staff plans to have a draft available by the end of December 2009.

The major criteria pollutant emissions are associated with the additional biorefinery truck trips. On a statewide basis, these emissions may be offset by reductions in motor vehicle emissions. However, there may still be localized diesel PM impacts and localized facility emissions impacts.

A health risk assessment was conducted to estimate the potential cancer risk associated with newly established biorefineries based on the facility specific emission inventory and air dispersion modeling predictions. The estimated potential cancer risk levels are associated with onsite diesel PM emissions from three co-located prototype biorefinery facilities. The area with greatest impact was estimated to be the area surrounding the facility fence lines with a potential cancer risk of over 0.4 chances in a million. The health risk assessment also examined combined onsite and offsite emissions of the three prototype biofuel facilities. The area with the greatest impact was estimated with a potential cancer risk of over five chances in a million.

Staff also quantified seven non-cancer health impacts associated with the change in exposure to PM2.5 emissions due to the operation of biofuel facilities. The analysis shows that the statewide health impacts of the emissions associated with the LCFS are approximately 24 premature deaths; 8 hospital admissions; and 367 cases of asthma, acute bronchitis and other lower respiratory symptoms.

Staff does not anticipate either a decrease or increase in the emissions from petroleum refineries, power plants, or corn ethanol facilities over the 2010 baseline. The capacity of the State's electric system in 2020 will be sufficient to support 1.8 million electric vehicles due to the 33 percent renewable portfolio standard and off-peak charging.

Also included in the environmental analysis is an examination of other environmental impacts of the LCFS on water quality and use, agricultural resources, biological resources, geology and soils, hazardous materials, mineral resources, and solid waste, among others.

Sustainability provisions will ensure that the LCFS regulation does not adversely impact the ability to continue the use of biofuels and other low carbon intensity fuels in the future. The most critical sustainability component, addressing land use change, is part of the LCFS regulation. To address other sustainability components, both environmental and socioeconomic, will require international cooperation and the development of enforceable certification standards. ARB is committed in the short term to develop a plan to address other sustainability components, and within two years of adoption of the LCFS will develop proposed sustainability criteria.

The ARB is committed to making the achievement of environmental justice an integral part of the LCFS. As such, staff seeks to develop tools to ensure that the proposed regulation does not disproportionately impact low-income and minority communities, does not interfere with the attainment and maintenance of ambient air quality standards, and considers overall societal benefits (such as diversification of energy resources). As part of ongoing AB 32 analysis, ARB staff is developing a screening method for geographically representing emission densities, air quality exposure metrics, and indicators of vulnerable populations, as an evaluation aide for already adversely impacted communities.

B. Greenhouse Gas Emission Benefits

In this section, ARB staff presents estimates of the GHG benefits associated with the LCFS. GHGs include, but are not limited to carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). In addition, staff has evaluated the contribution of various compliance options to the overall GHG emission benefits.

1. Determination of GHG Emission Reductions

In the AB 32 Scoping Plan, the LCFS is estimated to provide 15 MMT CO_2e emissions reduction in the year 2020. This value was derived by considering the baseline and projected business as usual case emissions in 2020, subtracting out the measures that would reduce the amount of fuel used, and then making an adjustment to ensure that the emissions reductions from electric vehicles are not double-counted. In that analysis, staff assumed that the LCFS would achieve a 10 percent reduction in the carbon intensity of the fuel used in California, which translated to a 10 percent reduction in emissions from fuel used in California. In effect, that analysis represented only the emissions from combustion and not the full lifecycle emission reductions.

In this analysis, we evaluated the benefits of the LCFS in two ways. In the first analysis, staff evaluated the fuel energy required to meet the LCFS standard in each year using only the "tank-to-wheel" carbon intensity. The "tank-to-wheels" analysis means that only the emission reductions seen at the tailpipe of the vehicles combusting low carbon fuels are considered. This analysis reasonably represents the emissions that would occur in California and is similar to the analysis used in the Scoping Plan. In addition, these reductions are the estimates of targeted emissions that would be compared to the targeted emissions in the Scoping Plan. In the second analysis, staff used the full lifecycle carbon intensity to estimate the overall CO2 emission reductions associated with the LCFS.

In general, the energy requirements necessary to meet the LCFS are a function of the estimates of fuel use required each year for transportation fuels. These estimates are projected from 2010 to 2020 using a business as usual scenario for both gasoline and diesel fuel. The fuel use is expressed in terms of gasoline gallon equivalent (gge) to account for the different types of fuel used (gasoline, diesel, CNG, electricity, hydrogen, etc.) In addition, the estimates are then adjusted by the other discreet early actions presented in the Scoping Plan. Chapter VI discusses these adjustments in more detail and presents a baseline case. The emissions estimates for each year are then projected by multiplying the respective baseline carbon intensities for gasoline and diesel fuel by the total energy required each year. Details of the analysis are presented in Appendix F1.

Table VII-1 presents the results for the tank-to-wheel analysis. As shown in the table, the total GHG emission reductions are 17.6 MMT CO_2e in 2020. About 70 percent of the emissions are associated with the gasoline pathway; the remainder from the diesel pathway. Table VII-2 presents the results for the full lifecycle basis. As expected, the GHG benefits are higher than just the "tank-to-wheel" estimates as they account for the full benefits of the LCFS. However, not all of these benefits are realized in California. Therefore, for purposes of tracking compliance with AB 32, staff recommends that the "tank-to-wheel" estimates be used.

Table VII-1
GHG Emission Benefits of the LCFS
"Tank-to-Wheel" Basis

Year	GHG Emission Reductions ($MMT\ CO_2e$)		
	Gasoline	**Diesel**	**Total**
2010	---	---	---
2011	0.3	0.1	0.4
2012	0.7	0.2	0.9
2013	1.3	0.5	1.8
2014	1.9	0.7	2.6
2005	3.2	1.3	4.5
2016	4.4	1.7	6.1
2017	6.3	2.5	8.8
2018	8.1	3.4	11.5
2019	9.7	4.3	14.0
2020	12.1	5.5	17.6*

*Please note that this does not include a 1.8 reduction to eliminate the double counting of the ZEV mandate. If this is included, the estimated total "tank-to-wheel" GHG benefits would be closer to 15.8 MMT CO_2e in 2020.

Table VII-2
GHG Emission Benefits of the LCFS
Full Lifecycle Basis

Year	**GHG Emission Reductions ($MMT\ CO_2e$)**		
	Gasoline	**Diesel**	**Total**
2010	---	---	---
2011	0.4	0.1	0.5
2012	0.9	0.3	1.2
2013	1.7	0.6	2.3
2014	2.5	0.9	3.4
2005	4.2	1.6	5.8
2016	5.8	2.2	8.0
2017	8.3	3.2	11.5
2018	10.6	4.3	14.9
2019	12.8	5.4	18.2
2020	15.9	7.0	22.9

2. Contribution of Low Carbon Fuels to GHG Emission Reductions

As discussed in Chapter VI, staff developed various compliance scenarios for meeting the LCFS. In these scenarios, staff presented examples of how producers can use a variety of fuels to achieve an average 10 percent reduction in the carbon intensity of the gasoline and diesel fuel. The following subsections discuss the contribution of the various fuels to achieving the overall GHG emission benefits.

a. Benefits from Gasoline Scenarios

Staff anticipates, as demonstrated in the scenarios discussed in Chapter VI, that various types of renewable biofuels, electricity, and hydrogen will be necessary to achieve the required GHG reduction goals for gasoline. Table VII-3 summarizes two potential scenarios. The first scenario emphasizes the use of renewable liquid fuels and the second uses an optimistic penetration of advanced technology vehicles, in combination with renewable fuels. These vehicles include plug-in hybrid vehicles, battery electric vehicles, and fuel cell vehicles. The table presents the percent contribution of each low carbon fuel to the total emissions reductions in 2020, as well as the actual MMT CO_2e. These contributions are based on the complete lifecycle of the fuels, with an overall reduction from the gasoline pathway of approximately 16 MMT CO_2e.

Table VII-3
GHG Reductions from Low Carbon Fuels Substituting for Gasoline

Fuel	Scenario 1 High Volume of Renewable Liquid Fuels		Scenario 2 Large Number of Advanced Vehicles	
	Percent Contribution	**MMT CO_2e**	**Percent Contribution**	**MMT CO_2e**
CA Low-CI Ethanol	2	0.3	2	0.3
Cellulosic Ethanol	43	6.8	28	4.4
Advanced Renewable Ethanol	41	6.6	27	4.3
Sugarcane Ethanol	3	0.5	3	0.5
Electricity	9	1.4	35	5.6
Hydrogen	2	0.3	5	0.8
Totals	100	15.9	100	15.9

b. Benefits from Diesel Scenarios

Staff anticipates, as demonstrated in the scenarios discussed in Chapter VI, that various types of renewable biofuels, natural gas, and electricity will be necessary to achieve the required GHG reduction goals for diesel. Staff anticipates advanced renewable and advanced biodiesel to provide the majority of the GHG benefits for the heavy-duty fleet. Advanced electric, fuel cell, and compressed natural gas vehicles are not expected to result in significant GHG benefits by 2020. Therefore, Table VII-4 provides only one scenario. As with gasoline, Table VII-4 presents the percent contribution of each low carbon fuel to the total emissions reductions in 2020, as well as the actual MMT CO_2e. The total tons were calculated based on an overall reduction of 7 MMT of CO_2e and are based on the complete lifecycle analysis of the fuels.

Table VII-4
GHG Reductions from Low Carbon Fuels Substituting for Diesel

Fuel	Scenario 1 High Volume of Renewable Liquid Fuels	
	Percent Contribution	**MMT CO_2e**
Conventional Biodiesel	13	0.9
Advanced Renewable Biodiesel	82	5.7
Compressed Natural Gas	2	0.2
Electricity	3	0.2
Totals	100	7.0

C. Air Quality Impacts

This section discusses the potential air quality impacts and public health risks related to potential sources and types of air emissions of identified lower-carbon fuel that may be used in the implementation of the LCFS. Low carbon fuels that may be used to comply with the LCFS include, but are not limited to, low-carbon ethanol, biodiesel, renewable diesel, electricity, hydrogen, and natural gas.

Below are descriptions of the pollutants of interest in this Chapter.

- Criteria Air Pollutants: Criteria air pollutants are determined to be hazardous to human health and are regulated under U.S. EPA's National Ambient Air Quality Standards. The 1970 amendments to the Clean Air Act require U.S. EPA to describe the health and welfare impacts of a pollutant as the "criteria" for inclusion in the regulatory regime. Both the California and federal governments have adopted health-based standards for the criteria pollutants that include ozone, particulate matter (PM_{10}, $PM_{2.5}$), carbon monoxide (CO), oxides of nitrogen (NO_x), oxides of sulfur (SO_x), and volatile organic compounds (VOC).

- Toxic Air Pollutants: Toxic air pollutants (also referred to as toxic air contaminants (TAC), or air toxics) are those pollutants which may cause or contribute to an increase in mortality or serious illness, or which may pose a hazard to human health. Air toxics are usually present in minute quantities in the ambient air. However, their high toxicity or health risk may pose a threat to public health even at very low concentrations. The toxic air pollutant of most concern in this analysis is the particulate matter from diesel-fueled heavy-duty trucks (diesel PM).

1. Overview of the Air Quality Analysis

The analysis of the potential air quality impacts of the proposed LCFS regulation was conducted in the same manner as the analysis of the GHG benefits. This "well-to-wheels" lifecycle analysis examines all potential air emissions from the production, transportation, and distribution of biofuels feedstocks; the actual production of biofuels; the transportation and distribution of biofuels (including dispensing to vehicles); and, finally the combustion biofuels in vehicles.

In this section, staff first presents an analysis of the number and location of biofuels facilities the State could support, as far as feedstock availability is concerned. Next, staff presents the various air quality regulatory requirements that apply to any biofuels facilities built in California. Following this discussion, the staff presents baseline emissions from the current production and use of transportation fuels in California. Then, staff presents the emissions that are estimated for the various cycles of production, distribution, and use of biofuels. Finally, staff compares the baseline emissions with those that are estimated to be associated with the implementation of the LCFS.

2. California Biofuel Production Facilities

Currently, there are two commercial scale corn ethanol facilities operating (approximately 100 MM gal/year), one small cellulosic ethanol facility under construction, and 9 small biodiesel facilities operating in California. Three additional commercial scale ethanol facilities are constructed, but are not currently operating for economic reasons. Construction was started on one additional commercial scale corn but construction was recently halted. Two other commercial scale corn ethanol facilities have been permitted, but are not currently under construction. For purposes of this analysis, we assumed that six corn ethanol facilities would be operating in 2010. Table VII-5 summarizes the capacity of these facilities in addition to the volume of gasoline and diesel produced in California.

Table VII-5
Production Capacity of Transportation Fuels in California
2010

Sources (# of facilities)	MMgal/year	MMgal(gge)/year
Petroleum Refineries (15)	18,400	18,960
Corn Ethanol Facilities (6)	310	440
Cellulosic Ethanol Facility (1)	3	2
Biodiesel Facilities (9)	63	73
TOTAL	**---**	**19,475**

The federal RFS2 and the proposed LCFS regulation will substantially increase demand for biofuels in California. Therefore, there may be incentives for bringing some of the existing and permitted corn ethanol facilities back on line, as well as incentives for constructing other biofuel facilities. For purposes of this analysis, staff estimated that there could be 30 large, commercial-scale biofuel production facilities (biorefineries) in California in 2020. This includes six commercial scale corn ethanol facilities. For this analysis, commercial-scale facilities are those facilities that produce approximately 50 million gallons per year. Table VII-6 shows the potential number of facilities in 2020, indicating which ones already exist and which ones might be built in order to meet the demands of RFS2 and the LCFS.

Table VII-6
Potential Number of Commercial-Scale
Fuel Production Facilities in California*
2020

Type of Facility	Existing	New	Total
Corn Ethanol	6	0	6
Cellulosic Ethanol	0	18	18
Biodiesel/Renewable Diesel	0	6	6

* Commercial-scale facilities are assumed to produce 50 MMgal/year each in 2020.

The analysis of the number and size of new biofuel production facilities is based on:

- The projected volume of biofuel needed to meet RFS2 requirements and the estimated volume of biofuel that could be used to meet LCFS requirements (see Chapter VI for an explanation of possible scenarios); and
- A report prepared by the University of California, Davis, for the Western Governors' Association (WGA)(76). The WGA report examines the potential for growth in the number, capacity, and location of biorefineries based on economic parameters.

Production facilities would be located in close proximity to local feedstocks. Biofuel production on a commercial scale will require development of new technologies as well as the continued use of conventional technology with crop-derived feedstocks. Non-crop feedstocks could include biomass wastes from forestry, municipal solid wastes, agriculture wastes, and waste oils.

Biodiesel production plants also tend to be located close to their feedstocks and secondarily close to rail yards or freeways for distribution to retail sites. Ethanol facilities tend to be located near rail or truck terminals. Ethanol facilities may also consider proximity to users of ethanol co-products during site determination.

Biofuels will be available to replace both gasoline and diesel with the split between the two fuel types difficult to quantify at this time. Based on the staff's analysis, the volume of biofuels that might be produced in California in 2020 could be 1.5 billion gallons of ethanol and 0.8 billion gallons of biodiesel. Potential locations in 2020 are listed in

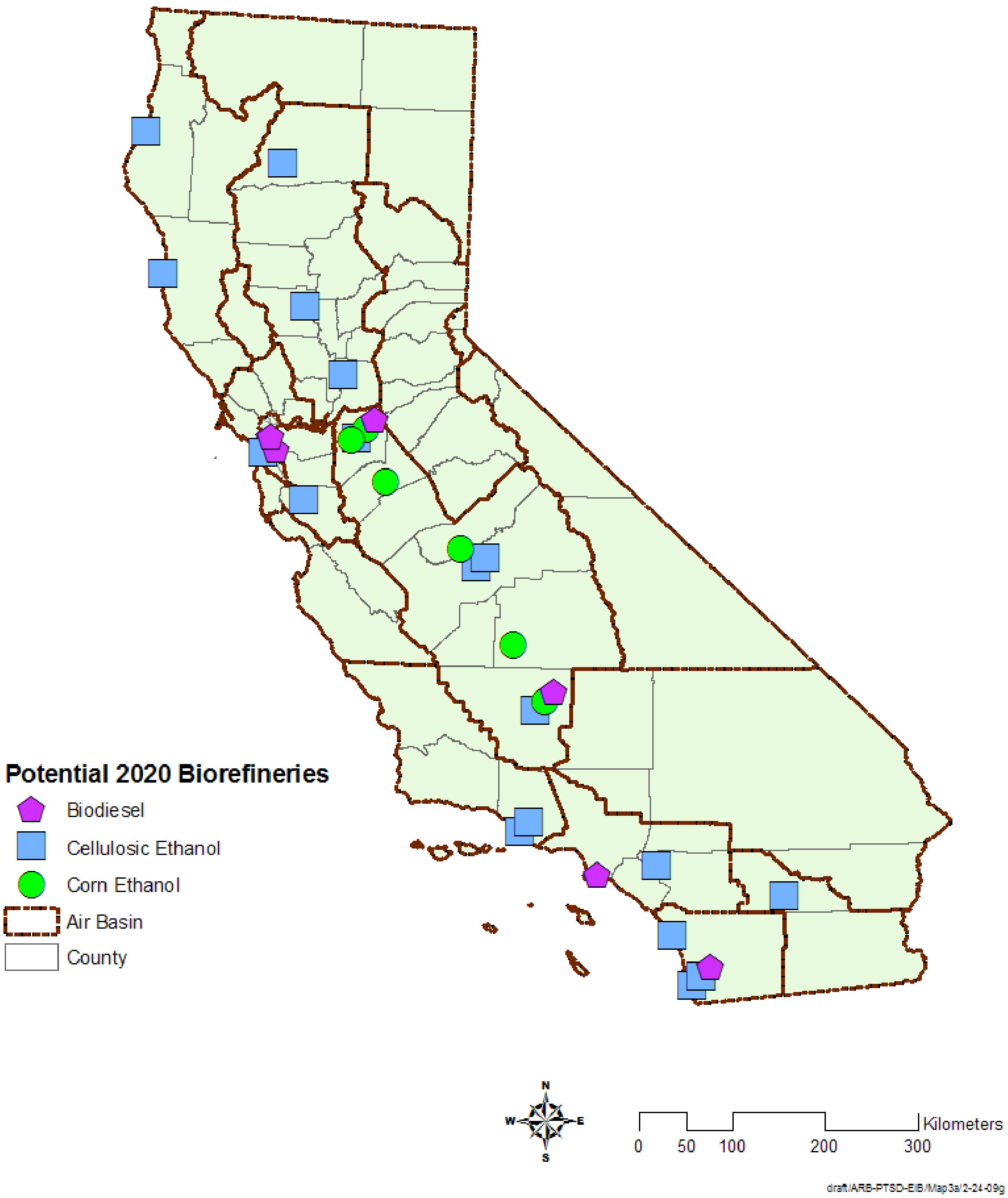
Table VII-7 and shown on a map in Figure VII-1. Additional details on the number and location of biorefineries and petroleum refineries is presented in Appendix F2.

Table VII-7
Location of Potential California Biofuel Production Facilities by 2020
(New Facilities are 50 MMgal/year)

Air Basin	Corn Ethanol	Cellulosic Ethanol	Biodiesel
North Coast		2	
Sacramento Valley		3	
San Francisco Bay		2	2[a]
San Joaquin Valley	6[c]	4	2[a]
South Central Coast		2	
South Coast		1	1[b]
Salton Sea		1	
San Diego County		3	1[a]

[a] Fischer-Tropsch process
[b] Non-esterified renewable diesel (hydrotreatment)
[c] Plants currently exist and are included in the baseline calculations

Figure VII-1
Map of Potential Biorefinery Locations in 2020



3. Permitting and Other Requirements

Under State law, the air pollution control and air quality management districts (local districts) have the primary responsibility for controlling air pollution from non-vehicular sources, including stationary sources such as biorefineries.[51] Each local district has a program designed to address new stationary sources of air pollution. For most local districts, these programs are referred to as new source review (NSR) programs.(77)[52] NSR programs provide mechanisms to: (1) reduce emission increases up-front through the use of clean technology, and (2) achieve a no net increase in emissions of nonattainment pollutants or their precursors for all new or modified sources that exceed particular emission thresholds. This is accomplished through two major requirements in each district NSR rule: best available control technology (BACT)[53] and offsets. The local districts also develop rules to reduce emissions from specific sources and govern the overall permitting process. Also, the local districts enforce their local rules and prepare local air quality plans to achieve ambient air quality standards.

In addition to meeting local district NSR rules, new biorefineries must meet California Environmental Quality Act (CEQA)[54] requirements as part of the permitting process. As these biorefineries are large industrial facilities, an environmental impact report (EIR) must be prepared. To comply with CEQA requirements, the EIR must identify any significant environmental impacts, identify feasible alternatives, and incorporate feasible mitigation measures to minimize the significant adverse environmental impacts identified in the environmental impacts analysis. CEQA requires that no project, which may have significant adverse environmental impacts, may be adopted as originally proposed if feasible alternatives or mitigation measures are available to reduce or eliminate such impacts, unless specific overriding considerations are identified that outweigh the potential adverse consequences of any unmitigated impacts.

The emissions estimates used for this air quality impact analysis reflect the use of the cleanest energy conversion technologies and air pollution control technologies. Even the use of the cleanest technologies can result in unmitigated emissions. However, ARB staff recommends that the emissions associated with the production of low carbon fuels be fully mitigated consistent with local district and CEQA requirements.
For cellulosic ethanol facilities, the energy requirements are typically greater than that for conventional ethanol facilities based on the conversion of corn starch. To provide additional information for local districts and to inform the CEQA process, ARB staff is committed to developing a guidance document to provide information on the best practices available to reduce emissions from these types of facilities. This effort will commence immediately; ARB staff plans to have a draft available by the end of December 2009.

[51] Health and Safety Code section 39002.
[52] See, e.g., Bay Area Air Quality Management District Regulations 2-1 through 2-6. A few local districts, because of their federal attainment status for certain pollutants, implement a Prevention of Significant Deterioration (PSD) program.
[53] In California, BACT is synonymous with the federal term Lowest Achievable Emission Rate (LAER) for nonattainment area permit requirements.
[54] Public Resources Code section 21000 et seq.

Based on the data currently available, there are several strategies that can be used to mitigate emissions and these have been generally incorporated into the analysis presented in this Staff Report. These include:

- Requiring the use of the best available control technologies;
- Requiring the use of the most efficient conversion technologies for the production of low carbon fuels;
- Requiring the maximum recovery of waste heat and other marketable products from energy conversion processes;
- Requiring the use of energy efficient air pollution control strategies;
- Eliminating, except for emergency purposes, the flaring or combustion of process waste fuels; and
- Requiring the use of vapor recovery to capture and re-use process evaporative emissions.

Appendix F3 contains additional information on mitigation and permitting requirements.

4. Emissions Estimates for Producing Low Carbon Fuels

The emission estimates are based on comparing the baseline emissions that would occur in 2020 versus the changes that might occur as a result of the LCFS. There are several assumptions that have been made in making this comparison. For petroleum production and refining, power generation, natural gas production, hydrogen production, and corn ethanol facilities, staff assumed that no significant changes in emissions between 2010 and 2020 would occur due to the LCFS. The major changes are due to the increased production of cellulosic and biodiesel facilities in California. These changes include feedstock and biofuel distribution and transportation and biofuel production facility emissions. For purposes of this analysis, we have assumed that the facility emissions are offset, although we present the cumulative emissions later in this section. We also evaluate the local and regional emissions for an individual and multiple co-located facilities.

In addition, the analysis presents a comparison of the emissions benefits that would result from the use of 2 million advanced vehicles versus the 1 million advanced vehicles.

a. Baseline Emissions

In order to determine the effects of the LCFS on California air quality, it is first necessary to determine the baseline emissions that currently exist from the production and use of transportation fuels in California. Table VII-8 presents the 2020 baseline without consideration of the LCFS. More details regarding the regional impacts of these facilities can be found in Appendices F2, F4, F5, and F6.

Table VII-8
Estimated 2020 California Transportation Fuel Baseline Emissions (tons/day)

Sources	Emissions (tons/day)				
	VOC	CO	NO_X	PM_{10}	$PM_{2.5}$
Petroleum Production, Refining, and Marketing(78)	104.5	40.0	43.9	7.8	7.4
Corn Ethanol Production[55]	0.28	0.39	0.92	0.13	0.12
Cellulosic Ethanol Production[2]	0.06	0.06	0.06	0.02	0.02
Biodiesel Production[56]	0.17	0.10	0.07	0.02	0.01
Electricity Production[57]	--	--	--	--	--
Hydrogen Production[4]	--	--	--	--	--
Natural Gas Production[4]	--	--	--	--	--
On- and Off-road Gasoline Vehicles[58]	636.04	4947.58	334.56	--	46.87
On- and Off-road Diesel Vehicles[7]	73.18	514.85	558.60	--	19.73
TOTAL	**814.23**	**5502.98**	**938.11**	**7.97**	**74.15**

b. Emissions from Feedstock Production, Transportation, and Distribution

Transportation fuels included in the LCFS are produced from a variety of feedstocks. These feedstocks include crude oil, natural gas, biomass material, biowaste material, waste grease, or municipal solid waste. In some cases, criteria pollutants are emitted during the process of feedstock production. Waste feedstock is considered to have no production criteria pollutant emissions. Estimates of feedstock production criteria pollutant emissions for the year 2020 are presented in Table VII-9. These estimates were calculated using a 2015 fleet average of diesel vehicles and includes the control measures put forth in the Scoping Plan. Approximately two-thirds of emissions from the 2020 fleet come from pre-2010 trucks; air districts could require facilities to mitigate associated truck emissions by requiring the use of 2020 or newer vehicles as a condition of permitting. Assumptions for these analyses can be found in Appendix F4.

---

[55] Based on permit values reported for California facilities (for complete list, see Appendix F) and includes transportation and distribution of feedstocks and finished fuels.
[56] Based on American Biodiesel permit, scaled linearly from 6.1mmgal/yr to 63 mmgal/yr and includes transportation and distribution of feedstocks and finished fuels.
[57] Electricity, hydrogen, and natural gas production contribute negligibly to the criteria pollutant emissions in 2010 because they are not currently being used in large enough quantities as transportation fuel
[58] On-road emissions based on EMFAC, includes Pavley I and II. Off-road emissions calculated using the Off-road Vehicle model.

Table VII-9
Projected 2020 Criteria Pollutant Emissions from Feedstock Production, Transportation, and Distribution above the Baseline

Feedstock	2020 Emissions Changes (tons/day)					
	VOC	CO	NO_x	SO_x	PM_{10}	$PM_{2.5}$
Crude Oil	--	--	--	--	--	--
Electricity	--	--	--	--	--	--
Natural Gas	--	--	--	--	--	--
Corn Ethanol[a]	--	--	--	--	--	--
Cellulosic Waste Feedstock[b]	0.02	0.33	0.80	0.02	0.02	0.02
Biodiesel Feedstock[c]	0.01	0.09	0.20	0.005	0.006	0.006

[a] No emissions are attributed to corn ethanol as no new facilities are expected to be built.
[b] Forest waste, orchard and vineyard waste, corn stover, straw, and/or municipal landfill waste.
[c] Beef tallow, pork lard and/or municipal landfill waste.

c. Emissions from Fuel Production Facilities

Criteria pollutants in 2020, above the 2010 baseline, for transportation fuel production facilities are shown in Table VII-10 below. Detailed calculations of cellulosic ethanol and biodiesel facility emissions can be found in Appendix F5. It should be noted that staff do not anticipate either a decrease or increase in the emissions from petroleum refineries, power plants, or corn ethanol facilities. In the case of petroleum, staff does not anticipate that refineries would operate at a lower capacity and any excess fuel above and beyond California's needs would be exported to neighboring states or elsewhere.

For electricity, the additional 1.8 million electric vehicles by the year 2020 assumed for this report are expected to increase the State's electric system load demand by 4.6 terawatt hours (TWh) by 2020. Since most of this additional demand would be supplied by off-peak power, electric vehicles would not create an adverse impact on California's supply of available electric power within the 2020 timeframe. Also, staff does not consider corn ethanol facilities to change by 2020, as they are currently using the best control technology currently available. Again, it should be noted that these facilities will be subject to permitting and mitigation requirements.

These estimates reflect:

- The most recent data gathered from permits and engineering evaluations for existing in-state facilities;
- Use of the cleanest energy conversion technologies and air pollution control technologies available;
- Emissions from stationary sources that do not require a permit; and
- Emissions from electrical back-up generators.

These emissions estimates do not reflect offsets, which we expect to be required.

Table VII-10
Projected 2020 Criteria Pollutant Emissions Changes from Fuel Production Facilities[a]

Sources	2020 Emissions Changes (tons/day)				
	VOC	**CO**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**
Petroleum Refineries[b]	--	--	--	--	--
Electricity Production[b]	--	--	--	--	--
Natural Gas Production[b]	--	--	--	--	--
Corn Ethanol Facilities[b]	--	--	--	--	--
Cellulosic Ethanol Facilities[c]	12.39	2.49	4.76	4.83	0.65
Biodiesel Facilities[c]	7.82	3.21	0.95	0.66	0.25
TOTAL	**20.21**	**5.70**	**5.71**	**5.49**	**0.90**

[a] Does not include offsets, which should be required in most cases.
[b] No additional emissions above the 2010 baseline.
[c] See Appendix F5 for details on how these estimates were made.

d. Emissions from Fuel Transportation and Distribution

Criteria pollutant emissions for the transportation and distribution of finished fuels were estimated for the year 2020. These emissions result in the movement of fuel in heavy duty-diesel trucks and railcars.

Production capacity of biorefineries in California in 2020 is not expected to supply the total volume of biofuels necessary for California transportation use. To acquire the necessary volume of biofuels, they will be imported from the Midwest. Ethanol is currently transported by unit train from the Midwest through Needles; Yuma; or Reno. The unit trains deliver ethanol to Selby and Carson. Ethanol is then delivered to CARBOB blending facilities or to storage facilities by heavy-duty diesel truck. In the future, biodiesel fuel is also expected to be imported in significant quantities into California. Biodiesel will likely be delivered from rail yard to vehicle fueling site by heavy-duty diesel truck. Finished transportation fuel is then delivered by tanker truck to fueling stations throughout the State.

Criteria and toxic emissions were estimated for the rail and truck transportation of ethanol and biodiesel fuels, shown in Table VII-11.

Table VII-11
Projected 2020 Criteria Pollutant Emission Changes from Fuel Transportation and Distribution[a]

Fuel	2020 Emissions Changes (tons/day)					
	VOC	**CO**	**NO_x**	**SO_x**	**PM_{10}**	**$PM_{2.5}$**
Finished Petroleum Products	--	--	--	--	--	--
Electricity	--	--	--	--	--	--
Compressed Natural Gas	--	--	--	--	--	--
Corn Ethanol	--	--	--	--	--	--
Cellulosic Ethanol[b]	0.04	0.05	3.58	0.001	0.069	0.063
Biodiesel[b]	0.011	0.047	0.61	0.002	0.004	0.003
Hydrogen	--	--	--	--	--	--

[a] Based on hypothetical optimized locations for cellulosic ethanol, corn ethanol, and biodiesel facilities.
[b] These transportation emissions include the rail emissions from imported cellulosic ethanol and biodiesel once they enter the state.

e. Emissions from Ports

Staff has considered the effect of the LCFS on port emissions. We anticipate that there would be little to no change to emissions at ports from feedstock delivery or finished fuel. Although we anticipate a decrease in demand for both crude and finished CARBOB from overseas, we expect California refinery production to remain constant. Therefore, surplus finished gasoline, which will be above and beyond our needs as our reliance decreases, will be shipped overseas.

f. Motor Vehicle Emissions

In order to meet the goals of the LCFS, staff has two basic approaches: (1) introducing lower carbon fuels and (2) employing vehicles that can use these lower carbon fuels. In this section, there is a discussion of several different vehicle technologies and how they compare to their appropriate gasoline or diesel vehicles. Table VII-12 shows the overall reductions in criteria pollutants staff anticipates from our projected 2020 fleet.

The criteria pollutant emission impact from Zero Emission Vehicle (ZEV) program is based on the benefit difference between the 2 million market-driven advanced technology vehicle (fuel cell, battery or plug-in hybrid electric vehicles) and the improved ZEV regulation of up to 1 million advanced technology vehicles.

The impact from the use of E85, B20, and CNG bio/renewable diesel assumes 15% of petroleum diesel will be displaced by renewable alternative diesel fuels (biodiesel 5% and renewable diesel 10%). It covers the criteria pollutants emissions changes from both on-road and off-road vehicles in 2020.

The criteria pollutant emissions impact from CNG is obtained by assuming 35,000 heavy-heavy-duty diesel vehicles will be replaced by CNG vehicles in 2020.

For E85, the vehicles are required to meet emission standards equivalent to those for gasoline vehicles. Therefore there are no emission increases from E85 versus gasoline vehicles. Staff estimated slight increase in refueling emissions due primarily to the larger number of refills. Since E85 has lower energy content than gasoline, people would have to fill up more often.

Table VII-12
Projected 2020 Criteria Pollutant Emission Changes
Due to an Increased Number of Advanced Vehicles

Vehicle	2020 Emissions Changes (tons/day)					
	VOC	CO	NOx	SOx	PM10	PM2.5
ZEV	-4.11	-38.36	-6.03	-1.21	-0.71	-0.41
B20	--	--	-2.20	--	-0.75*	-0.71
CNG	--	15.08	-1.64	--	-0.67	-0.63*
E85	0.23	--	--	--	--	--
Total	**-3.88**	**-23.28**	**-9.87**	**-1.21**	**-2.13**	**-1.75**

*: Number is obtained by assuming 94.7% of diesel PM is PM2.5.

<u>E85 vs. Gasoline Vehicles:</u>

One potential avenue to reduced greenhouse gas emissions is expanded use of E85 in place of gasoline. E85, however, must be used in flexible fuel vehicles (FFVs). Upgrades to the fuel distribution system are also required. This section examines the potential impacts to emissions of criteria pollutants and toxic air contaminants from switching from gasoline to E85. Given that both conventional gasoline and flexible fuel vehicles must meet the same emissions standards, it is reasonable to expect that the emissions levels will be similar. The following discussion presents aspects which are essential to examine E85's feasibility and environmental impact.

The number of vehicles and the emissions per vehicle on each fuel can be used to determine the change in emissions in switching from gasoline to E85. The population of FFVs is expected to increase between 2005 and 2020.

Staff estimates a maximum increase of 84 ton/year VOC evaporative emissions from refueling results in switching to scenario 2 volumes of E10 and E85 in 2020, as opposed to not switching from an energy equivalent volume of CaRFG3 fuel (E10). The other scenarios offer somewhat smaller increases.

Emission standards for vehicles which use E85 are the same as for vehicles which use gasoline. Therefore, staff does not expect to see a significant difference in the emissions.

A cursory review of California certification data for 2008 model year FFVs indicates that they are all compliant on both E85 and gasoline for all pollutants. While differences were slight, emissions of CO and NOx tended to be less on E85 than on gasoline, while emissions of VOC tended to be greater on E85 than on gasoline. Emissions of formaldehyde (HCHO) were also greater on E85 than on gasoline, showing a much larger difference, although there was only one pair of test values (DaimlerChrysler).

A literature search was conducted for E85 and FFV emissions. Results turned up mostly dated (1990s) publications and low-to-intermediate ethanol concentration fuels. Since that time, reformulated gasoline has emerged and vehicle technologies have changed considerably. Fewer recent publications are available. Emissions studies yielded mixed results; there does not appear to be a clear consensus as to whether E85 or gasoline has greater emissions.

At least two other vehicle studies are in the works, the Coordinating Research Council E-80 project, and the US EPA Comprehensive Gasoline Light Duty Exhaust Fuel Effects Test Program to Cover Multiple Fuel Properties and Two Ambient Test Temperatures.

Criteria pollutant and toxic emissions from motor vehicles using all fuels were estimated with the CA Modified GREET version 1.8b(47). Emissions data are located in Appendix F6.

<u>Biodiesel and Renewable Diesel vs. Diesel Vehicles:</u>

The main factors that will affect changes in emission rates from biodiesel as compared to diesel are feedstock composition, changes in engine technologies, and regulatory action. Biodiesel feedstocks can have a significant effect on emissions of ROG, PM, and NOx. NOx is of particular interest because biodiesel has been reported to increase NOx emissions. ARB staff has assumed that there will be no increase in the emissions of NOx. This is because staff is currently conducting an extensive test program for biodiesel and renewable diesel and will follow that effort with a rulemaking to establish specifications to ensure there is no increase in NOx.

For renewable diesel, the main factors are changes in engine technologies and regulatory action; however feedstock composition is not expected to affect changes in renewable diesel emission rates. Because renewable diesel is a high Cetane, ultra-low aromatic fuel, renewable diesel is expected to have lower emission rates of ROG, PM, and NOx than diesel fuel.

Another factor is the lack of data on how biodiesel and renewable diesel will affect emissions from 2010 on-road engines. The 2010 engine technologies are significantly different from current engines since they control both NOx and PM and emit lower emissions than uncontrolled engines. Staff expects that PM and NOx benefits from renewable diesel, and PM benefits from biodiesel, would be mainly from pre-2010 on-road, and uncontrolled off-road diesel engines. As the on-road and off-road diesel fleet regulations control more of the in-use fleet, the criteria pollutant benefits of renewable and biodiesel will decrease over time. For more details on the emissions from vehicles using biodiesel and renewable diesel, refer to Appendix F7.

Electricity and Hydrogen vs. Gasoline and Diesel Vehicles:

An analysis of three different deployment scenarios for light duty electric drive vehicles was performed to determine possible emissions reductions from various populations. The potential emissions reductions for the year 2020 range from 1.6 to 6.9 million tons/year of GHGs and 11,430 to 36,000 tons/year of criteria pollutants depending on deployment scenario.

Currently a limited number of zero emission hydrogen fuel cell buses (ZBus) are being used by transit fleets in demonstration projects. The number of vehicles is limited and expected to increase as the technology is validated and regulations facilitate the adoption of cleaner fleets. Future heavy duty vehicle populations have the potential to reach over 7300 units in 2020 due to emission reduction requirements placed on transit agencies. These vehicles demonstrate the potential for emissions of GHGs to be reduced by 16,200 tons/year and criteria pollutants by 1000 tons/year.

For detailed information regarding ZEV benefits, refer to Appendix F8.

CNG vs. Diesel Vehicles:

Staff analyzed the impacts of switching a number of diesel fueled HHDD trucks to CNG fuel to compare the change in PM and NOx emissions. This analysis was performed for 4,600 conversions by 2015 and 23,300 conversions by 2020. This analysis shows that switching from diesel fuel to CNG would result in a slight decrease in PM emissions, as well as a slight decrease in NOx emissions. Staff did not estimate any change in emissions of CO and NMHC. For more details, please see Appendix F9.

g. Summary of Impacts

The total criteria pollutant emissions for the production (after mitigation and offsets), transportation, and distribution of biofuels from the potential 24 new biorefineries listed above are summarized in Table VII-13. This summary is an overall estimate of the criteria pollutant impacts. The potential public health risks are discussed separately.

Clearly the major impact is associated with the additional truck trips. On a statewide basis, these emissions may be offset by reductions in motor vehicle emissions. However, there may still be localized diesel PM impacts and localized facility emissions impacts. These impacts are discussed in the next section.

Table VII-13
Summary of 2020 Changes from the Production and Use of Low Carbon Fuels above the Baseline (tons/day)

Criteria Pollutants Emissions	VOC	CO	NOx	SOx	PM10	PM2.5
Petroleum Refining, Production, and Marketing	--	--	--	--	--	--
Electricity Production	--	--	--	--	--	--
Natural Gas Production	--	--	--	--	--	--
Cellulosic Ethanol Facilities	--	--	--	--	--	--
Biodiesel Facilities	--	--	--	--	--	--
Impact from ZEV	-4.11	-38.36	-6.03	-1.21	-0.71	-0.41
Impact from Bio/Renewable Diesel	--	--	-2.20	--	-0.75[a]	-0.71
Impact from CNG Vehicles	--	15.08	-1.64	--	-0.67	-0.63[a]
Impact from E85 Vehicles	0.23	--	--	--	--	--
Impact from In-State Bio-Refinery Truck and Rail Trips	--	0.52	5.19	0.03	0.11	0.10
Total Impact	**-3.88**	**-22.76**	**-4.67**	**-1.18**	**-2.02**	**-1.65**

[a] Number is obtained by assuming 94.7% of diesel PM is PM2.5.

Emissions from biofuel facilities could come from the facilities themselves and associated truck trips. Staff assumes the in state biofuel facilities would have no facility emissions, because such emissions are required to be offset as a condition of permitting. Staff assumes the trucks to transport biomass to and biofuel from the facilities to be the 2020 fleet average, in which about 2/3 of the emissions come from the pre-2010 trucks. These emissions could be reduced if the air districts require the use of only 2010 or newer vehicles.

5. Analysis of the Potential Public Heath Risks

This section presents an analysis of the potential public health risks associated with the construction and operation of individual and co-located biofuel facilities.

a. Health Risk Assessment for Biofuel Facilities

The staff conducted a health risk assessment (HRA) study to evaluate the health impacts associated with toxic air contaminants emitted from typical biofuel facilities within California. The HRA focused on the potential cancer risk associated with diesel particulate matter (diesel PM) emissions caused by the biofuel facilities.

In order to estimate the potential cancer risk associated with a newly established biorefinery, ARB staff developed a prototype biofuel facility with 50 million gallon per year capacity. The prototype facility was located on a 200 meter by 200 meter square fence line. The emission sources from the facility include natural gas or biomass boilers and turbines. Diesel PM emissions are caused by the heavy duty trucks that are used to transport feedstocks and finished biofuel. Staff estimates an average of about 110 daily truck trips would be made to transport feedstock in and finished fuel out for a facility.

For the most conservative analysis, staff assumed that one main truck route connects a major freeway and three prototype biofuel facilities. The total diesel PM emissions from three facilities, including truck movements and idling, are about 0.004 tons per year. Staff defines this portion of emissions as “onsite”. The diesel PM emissions from the main and three individual truck routes are also directly caused by the biofuel facilities, although these routes are outside of the facility boundaries. The total diesel PM emissions from these routes are about 0.12 tons per year. Staff defines this portion of emissions as “offsite”.

The Health Risk Assessment (HRA) follows *The Air Toxics Hot Spots Program Risk Assessment Guidelines* (OEHHA, 2003) published by the California Office of Environmental Health Hazard Assessment (OEHHA). The HRA is based on the facility specific emission inventory and air dispersion modeling predictions.

As a result, the potential cancer risks levels associated with the onsite diesel PM emissions from the three collocated prototype biofuel facilities are displayed by using isopleths, based on the 80^{th} percentile breathing rate and 70 year exposure duration for residents. The area with the greatest impact has an estimated potential cancer risk of over 0.4 chances in a million, surrounding the facility fence lines.

Staff also estimated the health impact associated with the combined onsite and offsite emissions of the three prototype biofuel facilities. The area with the greatest impact has an estimated potential cancer risk of over 5 chances in a million. For more details regarding this modeling, see Appendix F10.

b. Ambient Ozone Impacts

National ambient ozone levels are regulated under the U.S. EPA national ambient air quality standards (NAAQS). To ensure attainment of the national standards in each state within specified time frames, U.S. EPA requires states to submit State Implementation Plans (SIPs) that show how each air basin within a state plans to meet the ozone NAAQS in the future. In the more populated and polluted areas, U.S. EPA requires that photochemical computer models be used to demonstrate the effectiveness of future regulatory emission controls on ambient ozone air quality.

The SIP air quality modeling process begins with replicating field measurements of hourly ozone concentrations for a period of days using a modeling system that is comprised of: (1) an EPA-approved photochemical model; (2) representative meteorological- and boundary condition inputs; and (3) a base case emissions inventory. After the modeling system has demonstrated the ability to reasonably replicate measured concentrations (i.e. based on regulatory model performance guidelines), it can be used to assess potential SIP control strategies for attaining- or maintaining ambient ozone levels prescribed in the NAAQS. In general, this attainment demonstration step is accomplished through a process of applying control strategy emission reductions to the baseline emissions inventory, then determining whether the corresponding model response at ozone field monitoring locations would yield the needed percentage reduction in measured ozone at those same locations to achieve attainment.

In theory, modeling systems used for SIP purposes can be used to assess air quality impacts for other regulatory purposes, such as the LCFS. However, due to the relatively small magnitude of emissions associated with LCFS (which are much less than the ~5% inventory delta that is an accepted minimum for grid-based modeling to avoid numerical artifacts), it is not practical to expect the air quality model to reasonably predict the impact on ozone air quality.

c. Health Impacts

A substantial number of epidemiologic studies have found a strong association between exposure to ambient PM2.5 and a number of adverse health effects (CARB, 2002). For this report, ARB staff quantified seven non-cancer health impacts associated with the change in exposure to PM2.5 emissions. This analysis shows that the statewide health impacts of the emissions associated with this regulation in year 2020 are approximately:

- 24 premature deaths (7 – 43, 95% CI)
- 3 hospital admissions due to respiratory causes (1 – 4, 95% CI)
- 5 hospital admissions due to cardiovascular causes (3 – 7, 95%CI)
- 340 cases of asthma-related and other lower respiratory symptoms (130 – 530, 95% CI)
- 27 cases of acute bronchitis (0 – 57, 95% CI)
- 2,200 work loss days (1,900 – 2,600, 95% CI)
- 13,000 minor restricted activity days (11,000 – 15,000, 95% CI)

Details on the health impacts assessment are included in Appendix F11.

d. Contribution to Impacts Assessment Method

As part of ongoing AB 32 analysis, ARB staff is developing a screening method for geographically representing emission densities, air quality exposure metrics, and indicators of vulnerable populations, as an evaluation aide for already adversely impacted communities. This work is not anticipated to be complete by the adoption of the LCFS. However, LCFS staff will continue to track this work and its applicability to future LCFS evaluations and is committed to conducting an analysis as methods develop.

The screening method under development is based on an ARB contract in progress with a team of academic researchers. The screening method uses geographic information system (GIS) tools and data to characterize a suite of parameters across census tracts for a region. The method will utilize measures of ambient air quality and emissions data derived from ARB's various criteria and toxic air pollutant programs, in order to provide indicators of current emissions and exposures to air pollution. Various measures may include, for example, particulate matter (PM) exposures and PM mortality, ozone exposures and adverse health effects, diesel and other toxic exposures and health effects, traffic densities, and other indicators of proximity to hazards. The screening approach would then couple these environmental indicators with another assessment for identifying indicators of vulnerable communities. Examples of these types of indicators include socio-economic census data such as poverty, ethnicity, housing and education, measures of linguistic isolation or lack of participation in the voting process, and representation of sensitive populations and land use, such as schools, day care centers, and hospitals.

Once areas have been characterized using this screening method, this information can be used in the future to help guide regulatory approaches that minimize community impacts, and to inform local decisions regarding siting and permitting alternatives.

D. Other Environmental Impacts

1. Water

This section briefly describes the water quality issues, water use impacts, and current regulatory requirements for the production and use of various low carbon "fuel" candidates. Eight candidate "fuels" were evaluated based on feedstocks, conversion technology and scale of conversion, resulting in a combination of seventeen scenarios without regard to the extent to which any of those fuels would be a part of a LCFS mix. Additional details can be found in Appendix F12.

a. Water Quality

Water quality issues include spills in transport, unauthorized releases during production or storage, unlawful disposal to storm sewers or even to WWTP. Releases of ethanol, biodiesel, and butanol blends to groundwater potentially contaminate drinking water with highly toxic petrochemicals (alkanes, BTEX and aliphatic compounds). Ethanol and biodiesel blends released to surface water may increase the likelihood and degree of fish kills compared to CARB gasoline and petroleum diesel because they deplete oxygen more rapidly.

Wastewater discharge volume from the production facilities range from none to high as described below, but regardless of the volume these facilities will need permits. With the exception of wastewater from pyrolysis operations that may be highly toxic, most wastewater discharges from the proposed LCFS facilities are not expected to be "toxic" per se, but may be high in salinity and BOD and therefore prohibited from discharge to land or water. In some cases the limitations on water discharge from production facilities may limit the development of the LCFS options in California.

b. Water Use

Water supply and consumption is a major issue in California and the State Water Board is responsible for surface water rights adjudications and the protection of their “beneficial uses”. Ownership of virtually every drop of surface water in California has been established. Surface water is neither free nor easily available. Even when water supplies can be acquired, the Water Boards may limit use if the removal of fresh water from a watershed basin adversely impacts the environment, ecology, or other beneficial uses.

Groundwater is not adjudicated statewide, but is limited in some areas. The Water Boards instead encourage the use of treated wastewater to produce fuels and irrigate feedstock crops where possible.

The production of fuels that consume very large quantities of water may be limited by available local supply and impacts on beneficial uses, and further limited to specific supplies such as Waste Water Treatment Plant (WWTP) ocean discharges.

Table VII-14 below estimates the worse case water consumption scenario of the LCFS mix.

Table VII-14
Water Consumption During Biofuel Production

Fuel	# plants	gWater/ gFuel	Total Fuel Production (mmgal)	Total Water (mmgal)[a]
Cellulosic EtOH	18	6	900	5400
Corn EtOH[b]	6	3.5	300	1050
Biodiesel	6	0.5	300	150
Total				**6600**

[a] Recycled water can be used for these processes
[b] The estimate for water use for corn ethanol does not include the impacts of irrigating the corn crop, as it seems unrealistic to assume that any corn for fuel would be planted in the state. For more information regarding the corn irrigation, please see Appendix F12.

Proponents of ethanol production facilities should consult with the Region Water Boards and the State Water Board, Division of Water Rights prior to committing to a location in order to confirm that sufficient water is available and that the State and Regional Boards have no objections to the use of that water.

Groundwater supply is not adjudicated or regulated by the State Water Board per se, but there is often competing local demand for groundwater.

Although recycled wastewater from a local wastewater treatment plant (WWTP) may be available for irrigation and process water, proponents of ethanol plants in the California

Central Valley and other water scarce areas are advised to confirm the availability of such water especially during periods of low surface water flow.

Ocean discharge from coastal WWTPs is a more reliable source of process water than WWTP discharge to land and the available volume easily exceeds the water supply requirements of the entire LCFS scenario above by several orders of magnitude. In fact, WWTP discharge to the ocean in California could supply enough water to support a 100% hydrogen economy. The available annual ocean discharge from WWTP can supply sufficient water 'feedstock' to produce enough hydrogen to supply over 1000% of California's 2007 gasoline consumption on a Btu basis.

Thus the proposed LCFS candidate fluid fuel production schemes should not create a water consumption problem if sited near large coastal WWTP and use ocean discharge.

c. Regulatory Requirements

The Water Boards regulate water discharges from any fuel production facility including electric power plants, as well as, the storage of any fuel in underground storage tanks UST. The Water Boards also protect and regulate the "beneficial use" of California's water including the impact on beneficial uses posed by water consumption in the production of energy.

Water related environmental and regulatory issues which fall entirely or in part within the authority of the State Water Board include water use, wastewater discharge from production facilities, toxicity of wastewater discharges, water quality related to ecology and other beneficial uses, permits required for production and storage of these fuels, and other regulatory limits on storage of fuels which do not necessarily require a permit.

2. Aesthetics

Any impacts associated with aesthetics, siting and construction of facilities supporting the LCFS would be assessed on a location and project-specific basis.

3. Agricultural Resources

The LCFS result in significant impacts to agricultural resources. The conversion of prime farmland, unique farmland or farmland of statewide importance due to siting of new facilities and its associated supporting infrastructure, or conflict with an existing Williamson Act contract may be significant. Further, the loss of food and fiber for fuel may increase the cost of food if the acreage had formerly been used to grow food crops. With mitigation measures such as avoidance of siting facilities on prime farmland, supporting the California Farmland Conservancy Program, working cooperatively with the landowners, and ensuring conformity with existing Williamson Act contracts, impacts would be substantially mitigated. Existing stationary source locations are presently, and would continue to be, primarily designated as heavy industrial land uses.

While future facilities that support the LCFS may be sited on prime agricultural lands, this is unlikely as prime agricultural land is too valuable to be used to grow crops for biofuel production. If siting of facilities results in the conversion of agricultural land, this would be subject to the CEQA process and approval by the city or county on a project-by-project basis. Siting of new stationary sources that convert biomass to fuel may convert prime farmland to other uses – the degree of which would be determined locally, and may conflict with an existing Williamson Act contract. Facilities associated with the LCFS measure would require local approval of conditional use permits, local air permits and possibly waste discharge requirements and would be subject to project-specific compliance with CEQA. Such conversion could be mitigated via a financial throughput mechanism that supports the California Department of Conservation's California Farmland Conservancy Program. Avoidance of siting a facility on Williamson Act contracted land would alleviate potential impacts associated with contract conflicts.

4. Biological Resources

The LCFS may adversely impact biological resources when new facilities are sited and constructed or existing facilities are expanded. Project and site-specific analysis and coordination with federal, state and local agencies would be necessary to obtain pertinent information regarding sensitive species within and surrounding a project area. Mitigation measures would be dependent upon the site survey and analyses. Project-level compliance with CEQA, and if appropriate, NEPA would be necessary. Until the proposed locations of the facilities are known, it is not possible to determine significance of impact.

When converting natural lands or farmlands to industrial or a utility-scale facility, such as an ethanol facility, any adverse impacts are required to be addressed and mitigated through CEQA. These impacts could be to terrestrial, riparian, or aquatic habitat, natural communities, or to any species identified as a candidate, sensitive or special status species in local or regional plans, policies or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service, or §404 of the Clean Water Act. A facility may interfere with the movement of any native resident or migratory fish or wildlife species with established migratory corridors, or it may conflict with the provisions of an adopted Habitat Conservation Plan or other approved local, regional or state habitat conservation plan.

In addition, the refining, marketing and distribution of petroleum fuels may adversely impact water quality due to leaks, spills, and wastewater discharge. These water quality impacts can also impair important habitat, or interfere with critical life-cycles of native species. Any reduction in petroleum fuel use would reduce the opportunity for such occurrences.

Some biofuels feedstocks have the potential to affect native species and biological resources, if feedstocks are produced though conversion of important habitat to agriculture or increase agricultural activities in species' corridors.

Hydrogen production and use should have little or no affect on native species and biological resources outside of any potential effects from its energy and water source.

Specific information will be evaluated as the measures and regulations are further developed; each regulation is required to have its own environmental evaluation. CEQA and possibly NEPA compliance would be required for each facility with its project-specific environmental evaluation. Figure J-1 depicts known and proposed locations of biofuel facilities.

5. Cultural Resources

Site-specific significant adverse impacts to cultural resources are not expected because the LCFS would not require destruction or alteration of any buildings or sites with prehistoric, historic, archeological, religious or ethnic significance. However, siting, grading, construction or expansion of facilities or buildings on lands that have not been surveyed for cultural significance, may result in adverse impacts to cultural resources if inadvertent disturbance occurs at the time of construction.

Location and project-specific compliance with CEQA and/or NEPA would be required for individual projects. The lead and implementing entities would be required to contact the appropriate agencies and departments to ensure that potential impacts to cultural resources would be minimized or avoided. As ARB staff cannot speculate on the locations of these resources, it is not possible to ascertain the impacts on cultural resources at this level.

6. Geology and Soils

At this time, implementation of the LCFS is not expected to expose people or structures to potential substantial adverse effects that involve risk of loss, injury or death from rupture of a known earthquake fault, strong seismic ground shaking, seismic-related ground failure, landslides, or result in soil erosion or be located on a geologic unit or soils that is unstable. The LCFS may involve siting, grading, construction or expansion of facilities or buildings and may require disruption or over covering of soil during construction of facilities. There may be changes in topography or surface relief features, the erosion of beach sand, or a change in existing siltation rates. At this time, ARB cannot speculate on the significance, as any future facility siting, construction or expansion would be required to be evaluated on a project specific basis, and would need to comply with state and local requirements that would mitigate impacts.

7. Hazards and Hazardous Materials

Impacts from the hazardous waste associated with the LCFS are not expected to be of major significance because the hazardous materials produced from biofuels production can generally be recycled, reprocessed, and reused. Additionally, facility operators will want to minimize generated wastes to minimize operational costs. They will be encouraged to create zero-waste facilities through sale of all products and co-products (ethanol, carbon dioxide, and wet distiller grains, etc.) for offsite use. Any hazardous waste generated (e.g., during a "process upset") that cannot be reused would require appropriate transport and disposal at a permitted facility.

Current state-of-the-art dry milling ethanol plants generate minimal waste. Much of the material resulting from ethanol production is actually co-product that can be used for other purposes. For example, distillers grains (DGs), sometimes called mash, and syrup which is called evaporated thin stillage can be mixed and used for feed. Any waste materials (e.g., waste hydraulic oil) that is generated would require appropriate disposal if the materials cannot be reused or reprocessed.

The production of biodiesel uses sodium hydroxide, hexane, sulfuric acid, and methanol. These will be present in any waste generated. Glycerol is a co-product that contains unused catalyst, salt, water, methanol, and soaps, and may be recycled as it has economic value. Stearates are likely generated during the esterification process as well. Hazardous waste materials that cannot be reused or reprocessed would require appropriate disposal.

Automobile manufacturers have indicated plans to incorporate lithium-ion battery technology for electricity storage in future PHEVs, BEVs and FCVs vehicles. It is expected that lithium automotive batteries will not be disposed of in landfills. This is due to the economic value of the lithium along with regulations prohibiting disposal. If the lithium batteries obtained from vehicles are not placed in service for other energy storage or other power applications, they will likely be recycled prior to the disposal of the vehicle.

There are numerous alternative production methods being proposed for hydrogen fuels. In the production of hydrogen fuels there is minimal generated waste. Hydrogen production is actually being proposed using various waste streams. Other production methods use metals as catalysts. These metals can generally be recycled minimizing residual waste.

The operation of biofuel facilities will involve the transportation of hazardous materials that could be released on roadways. These materials could include ethanol, biodiesel, unleaded gasoline, sulfuric acid, aqueous ammonia, and urea. Although these materials are currently carried on roadways, there will be an increase in the use and transportation of these materials. There should be no impact to public or the environment through the routine transport, use, or disposal of hazardous materials. The biofuel facility operators will be expected eliminate any significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment.

Additional information on hazardous waste is presented in Appendix F13.

8. Mineral Resources

The LCFS is not expected to cause any adverse impacts on mineral resources. The measures are not expected to deplete non-renewable mineral resources at an accelerated rate or in a wasteful manner. There are no anticipated significant adverse impacts to mineral resources. It should be noted that an increased ZEV population might have some effect on the lithium supply. This is discussed in detail in Appendix F8.

9. Housing and Population

The LCFS is not expected to cause any adverse impacts to population or housing. The proposed measures are not expected to result in the creation of any industry that would significantly affect population growth, or directly or indirectly induce the construction of single- or multiple-family units. No significant population relocation or growth inducement is expected.

10. Public Services

The LCFS is not expected to cause any adverse impacts to public services. Any need for an unforeseen public service would be subject to project-specific CEQA analysis or NEPA analysis by federal agencies.

11. Recreation

The LCFS is not expected to affect recreational opportunities in the State. To the extent that specific industries propose to construct facilities in protected lands to meet statutory or regulatory requirements, these projects would be required to go through NEPA and CEQA review prior to approval.

12. Solid Waste

Solid waste consists of residential wastes (garbage and rubbish produced by households), construction wastes, commercial and industrial wastes, home appliances and abandoned vehicles, and sludge residues (waste remaining at the end of sewage treatment process). CCR Title 14, Division 7, provides the State standards for the management of facilities that handle and /or dispose of solid waste. CCR Title 14, Division 7 is administered by the California Integrated Waste Management Board (CIWMB) and the designated Local Enforcement Agency (LEA). The LEA for each county is the County Department of Environmental Health, and some cities have LEAs.

CCR Title 14, Division 7, establishes general standards to provided required levels of performance for facilities that handle and /or dispose of solid waste. Other Title 14 requirements include operational plans, closure plans, and post-closure monitoring and maintenance plans. Title 14 covers various solid waste facilities including but not limited to landfills, material recovery facilities (MRF), transfer stations, and composting facilities.

Potential adverse waste impacts are not expected to be significant. The proposed measures are not anticipated to result in a substantial increase in the generation of solid waste or require that any permitted facility to expand its capacity to accommodate increased quantities of waste. For more details, see Appendix F14.

13. Transportation and Traffic

The LCFS is not expected to cause significant adverse impacts to transportation or traffic. Construction related impacts associated with the LCFS are expected to be temporary. During construction of facilities, traffic impacts can be mitigated through ingress and egress controls to mitigate for congestions, and facility design should include appropriate traffic controls such as turn lanes, traffic lights, and reduced speed zones to ensure safety.

E. Sustainability

From an LCFS perspective, sustainability implies that current production and use of biofuels to meet the LCFS must not adversely impact the ability to continue its use in the future. Sustainability encompasses a variety of environmental, economic, and social components. These include GHG emissions, conservation of high carbon stock land, conservation of high biodiversity land, air quality, water use, water quality, soil conservation, genetically modified organisms, labor rights, (working conditions, worker rights, child labor, forced labor), land rights (displacement of indigenous people), environmental justice, food price and food security.

The U.S. and several other governments (United Kingdom, Germany and Netherlands) have either passed laws, proposed policies, or implemented policies for the sustainable production of biofuels. The proposed policies by the United States, United Kingdom, Germany, and Netherlands have key similarities: they address common environmental and social principles, they use existing standards to certify sustainability, and they intend to tighten sustainability policy over time. Additionally, various other government organizations have committed to developing low carbon fuel standards. These include the Northeastern/Midwestern states, as well as the Canadian provinces British Columbia and Ontario.

Supra-national (European Union) and international organizations (United Nations Environment Prohramme(79), Roundtable on Sustainable Biofuels(80), Food and Agriculture Organization of the United Nations(81)) are also addressing sustainable biofuels production. These organizations are in the process of developing sustainability criteria, as well as certification standards, that could be used to evaluate the sustainability of biomass production. The Roundtable on Sustainable Biomass (RSB) has released its draft ‘generic’ standard (‘Version Zero’) that can be applied to any feedstock.

The Energy Commission is developing sustainability goals (and their associated sustainability characteristics) as part of its role in administering AB 118-funded projects. The sustainability characteristics will form the basis of a set of evaluation criteria that will be used to assess how well each proposed project can meet the sustainability goals. ARB and the Energy Commission are working together to ensure that sustainability principles developed for the LCFS and AB118 are consistent.

Sustainability, as it pertains to the LCFS, is complex. Currently, there is not enough information available to develop relevant and detailed sustainability strategy or standards. The most likely method for establishing sustainability in the production of biofuels on a global scale is the adoption of certification standards. Such standards will have to address universally accepted sustainability components, have well developed criteria and criteria indicators, and be verifiable by certified third parties (which will in turn have to be certified by accrediting bodies). The components of a universally accepted certification standard might include but are not limited to:

- Well defined sustainability criteria and their associated indicators on a plantation level;
- Methods for assessing the cumulative impacts of many “sustainable” operations on a regional or global level;
- Certification process to establish whether the standard has been met; this includes defining the auditor’s qualifications & training, the audit process, consultation, reporting of the information, mechanism for dealing with complaints;
- Accreditation requirements: an accreditation body accredits certification bodies (certifiers) based on systems, records, and/or processes. ISO 17011 provides the general requirement for bodies providing assessment and accreditation of conformity assessment bodies. The ISO 17021 is more specific for bodies providing audit and certification of management systems. ISO 65 is used in case of product certification. The accreditation body may demonstrate competencies either by adhering to the appropriate International Accreditation Forum (IAF) Multilateral Recognition Arrangement (MLA) or through membership of the International Social and Environmental Accreditation and Labeling Alliance (ISEAL); and
- Chain of custody rules.

The ARB will work together with other State agencies, national and international organizations, non-government organizations, and other interested parties to develop an appropriate sustainability strategy. By December 2009, ARB staff intends to develop a strategic plan for addressing overall sustainability provisions for the LCFS, for consideration by the Board at its first formal public review scheduled for the end of 2011.

F. Multimedia Evaluation

Senate Bill 529, enacted in 1999 and set forth in Health and Safety Code (H&S) section 43830.8 ("the statute"),[59] generally prohibits ARB from adopting a regulation establishing a specification for motor vehicle fuel unless the regulation is subject to a multimedia evaluation by the California Environmental Policy Council (CEPC). (Stats. 1999, ch. 813; SB 529, Bowen.) Pursuant to Public Resources Code section 71017(b), the CEPC was established as a seven-member body comprised of the Secretary for Environmental Protection; the Chairpersons of the ARB, State Water Resources Control Board, and Integrated Waste Management Board; and the Directors of the Office of Environment Health Hazard Assessment, the Department of Toxic Substances Control, and the Department of Pesticide Regulation. Key components of the evaluation process are the identification and evaluation of significant adverse impacts on public health or the environment and the use of best available scientific data.

"Multimedia evaluation" means the identification and evaluation of any significant adverse impact on public health or the environment, including air, water, or soil, that may result from the production, use, or disposal of the motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specifications. H&S §43830.8(b).

Notwithstanding the general prohibition noted above, the statute provides that ARB may adopt a regulation establishing a specification for motor vehicle fuel without the proposed regulation being subject to a multimedia evaluation if the CEPC, following an initial evaluation of the proposed regulation, conclusively determines that the regulation will not have any significant adverse impact on public health or the environment. This raises three issues, all of which are addressed in this Staff Report:

(1) whether the proposed LCFS regulation establishes a motor-vehicle fuel specification in the first place that would require a multimedia evaluation;

(2) whether the proposal is expected to have any significant adverse environmental impacts on public health or the environment; and

(3) whether the multimedia evaluation requirement applies to subsequent rulemakings to implement the LCFS regulation, even if the multimedia evaluation requirement does not apply to the LCFS regulation itself.

As discussed below, ARB staff has determined that the proposal itself neither triggers the multimedia evaluation requirement nor is it expected to have significant adverse impacts on public health or the environment. But the multimedia evaluation requirement may apply to subsequent rulemakings to implement the LCFS regulation to the extent such rulemakings establish motor-vehicle fuel specifications.

[1]All statutory references in this chapter are to H&S §43830.8 unless otherwise noted.

1. Does the Proposal Establish a Motor-Vehicle Fuel Specification?

With regard to the first issue, Chapter V (Summary of the Proposed Regulation), Section J (Requirements for Multimedia Evaluation) contains the staff's legal rationale for its determination that the proposal does not trigger the multimedia evaluation requirement in the first place. As noted in that discussion, the proposed regulatory action does not establish any motor-vehicle fuel specifications. This is because the proposal contains no requirements that dictate the exact composition of compliant transportation fuels under the LCFS regulation. By its terms, the proposed regulation does not in any way amend, repeal, modify or otherwise change in any way any existing State or federal fuels regulations or any other applicable regulations.[60] Because the proposal does not establish a motor-vehicle fuel specification in the first place, the multimedia evaluation requirement under H&S 43830.8 is not triggered.

To illustrate, the proposal does not establish any specifications for CaRFG3 gasoline and will not require a gasoline ingredient to be added or removed beyond what is already used to produce gasoline for sale in California. Similarly, the proposal does not change any specifications for CARB diesel and will not require a diesel ingredient to be added or removed beyond what is already used to produce diesel for sale in California. Further, the proposal does not change or adopt any specifications for natural gas, liquefied petroleum gas, biodiesel, renewable diesel, hydrogen, or electricity. Therefore, as discussed more extensively in Chapter V, staff believes that the proposed rulemaking is not subject to the requirement for a multimedia evaluation.

2. Is the Proposal Expected to Have Significant Adverse Environmental and Public Health Impacts?

While we believe the proposal is not formally subject to the multimedia evaluation requirement, staff believes there is merit in conducting a functional equivalent of a multimedia evaluation, as noted in Chapter V. Such a functional equivalent would evaluate the expected environmental and public health impacts from the proposal to the extent feasible and based on the best available data.

To this end, staff believes the environmental impacts analysis in this Chapter VII amply serves the role of a functional equivalent analysis. Thus, with regard to the second issue noted above, the staff has determined that the proposal will not have significant adverse environmental impacts on public health or the environment. This determination is based on our environmental impacts analysis contained in this Chapter VII.

3. Does the Multimedia Evaluation Requirement Apply to Post-LCFS Rulemakings?

We should note that subsequent rulemakings establishing specifications for motor vehicle fuels will be subject to H&S §43830.8. Future rulemakings planned by ARB that

[60] See section 95480.1(e) of the proposed LCFS regulation.

may establish such motor-vehicle fuel specifications include proposals to adopt new specifications for biodiesel, compressed natural gas, E85, and biobutanol. To the extent such future rulemakings establish specifications for motor vehicle fuels, the provisions of H&S section 43830.8 would apply.

G. Environmental Justice

As the Scoping Plan is implemented and specific measures are developed, ARB and other implementing agencies will also conduct further analyses, including cumulative and multi-media impacts. ARB must design equitable regulations that:

- Encourage early action;
- Do not disproportionately impact low-income and minority communities;
- Ensure that AB 32 programs complement and do not interfere with the attainment and maintenance of ambient air quality standards;
- Consider overall societal benefits (such as diversification of energy resources);
- Minimize the administrative burden; and
- Minimize the potential for leakage.

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 mechanisms, 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 in future rulemakings, and updates needed analytical tools and data sets, we will consult with outside experts and the Environmental Justice Advisory Committee.

ARB already conducts robust environmental and environmental justice assessments of our regulatory actions. Many of the requirements in AB 32 overlap with ARB's traditional evaluations. In adopting regulations to implement the measures recommended in the Scoping Plan, or including in the regulations the use of market-based compliance, mechanisms to comply with the regulations, ARB will ensure that the measures have undergone the aforementioned screenings and meet the requirements established in HSC §38562 (b) (1-9) and §38570 (b) (1-3).

The ARB is committed to making the achievement of environmental justice an integral part of the LCFS. As such, staff seeks to develop tools to ensure that the proposed regulation does not disproportionately impact low-income and minority communities, does not interfere with the attainment and maintenance of ambient air quality standards, and considers overall societal benefits (such as diversification of energy resources). As part of ongoing AB 32 analysis, ARB staff is developing a screening method for geographically representing emission densities, air quality exposure metrics, and indicators of vulnerable populations, as an evaluation aide for already adversely impacted communities.

To provide additional information for local districts and to inform the CEQA process, ARB staff is committed to developing a guidance document to provide information on the best practices available to reduce emissions from these types of facilities. This effort will commence immediately; ARB staff plans to have a draft available by the end of December 2009.

VIII. Economic Impacts

In this chapter, staff presents the estimated costs and economic impacts associated with the implementation of the proposed regulation. The economic analysis includes estimated costs for fuel providers of potential compliance pathways, an analysis of the cost-effectiveness of the proposed regulation, and the costs and associated economic impacts on businesses, consumers, and government agencies. Additional cost information is included in Appendix G.

A. Summary of the Economic Impacts

For the economic analysis of the LCFS, staff estimated the costs of producing the petroleum-based fuels—gasoline and diesel—and the costs of producing the lower-carbon-intensity transportation fuels that could be used in combination with petroleum fuels to meet the LCFS. Staff applied these costs to possible compliance scenarios for both diesel fuel and gasoline. Each of these possible scenarios includes an assumed mix of fuels that satisfies the LCFS reduction targets.

Staff estimated that the displacement of petroleum-based fuels with lower-carbon-intensity fuels will result in an overall savings in the State, as much as $11 billion from 2010 -2020. These savings may be realized by the biofuel producers as profit, or some of the savings may be passed on to the consumers. Should the savings be entirely passed on to consumers, it would represent less than three percent of the total cost of a typical gallon of transportation fuel ($0 - $0.08/gal).

Staff understands that the economic analysis of the LCFS is greatly affected by future oil prices and the actual production costs and timing of lower-carbon-intensity alternative fuels. Economic factors, such as tight supplies of lower-carbon intensity fuels or a lengthy economic downturn keeping crude demand and hence prices down, could result in overall net costs, not savings, for the LCFS.

Staff determined that approximately 25 new biorefineries could be built in California based on an assessment of potential feedstocks. Biofuel producers are expected to eventually recoup their costs through the sale of lower-carbon-intensity fuels, while consumers should see no significant changes in fuel prices to some savings. In addition to liquid fuels, such as ethanol and biodiesel, other lower carbon-intensity fuels, including electricity, hydrogen, and compressed natural gas (CNG) may be used to meet the requirements of the LCFS.

The proposed regulatory action would not affect small businesses because: (1) most, if not all, regulated parties are expected to be relatively large businesses, and (2) small businesses (generally the fueling station owners and operators) would presumably invest in equipment that dispenses LCFS-compliant fuel with the expectation that the costs of such an investment would be recouped through sales of such fuels.

Staff conducted the economic analyses considering all costs of production and distribution of alternative transportation fuels, which, as mentioned above, resulted in overall savings to the State. Staff then recognized that the federal Renewable Fuel Standard (RFS2) will bring significant quantities of ethanol to California, and that the infrastructure required to meet the mandates of RFS2 is essentially the same infrastructure necessary to meet the potential ethanol requirements of the LCFS; therefore, nearly all of the ethanol-related infrastructure costs can be attributed to RFS2.

RFS2 and the proposed LCFS regulation will result in a shift of capital from the petroleum sector to the agricultural, chemical, electricity, and natural gas sectors. This redistribution of capital among these sectors is essential to the success of the LCFS and RFS2. The diversification of California's transportation fuels, which requires a shift of capital from the petroleum sector, is consistent with well-established national and State policies.

The regulation would create costs to the State in the form of lost transportation-fuel taxes, including excise taxes and sales tax. Although there would be no estimated fiscal impact for the first three years of the proposed regulation, staff estimates the potential loss of annual state tax revenue to be $80 million to $370 million in 2020—the year of greatest impact—depending on compliance path(s) chosen. For local government, the impact of sales tax on transportation fuels from implementing the potential compliance scenarios could either create revenue or result in a revenue loss, depending on the compliance path(s) chosen. The impacts to local sales taxes would be location specific. Although there would be no fiscal impact for the first three years of the proposed regulation, staff estimates a potential range of impacts in annual local sales tax revenue of -$51 million to +$2 million from 2013 – 2020.

B. 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 (DOF). 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 the Air Resource Board (ARB or Board) to perform an economic impact analysis 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.

C. Methodology for Estimating Costs

This section provides the general methodology and assumptions used to estimate the costs associated with the proposed regulation.

The proposed regulation requires producers, importers, and some other providers of transportation fuels to meet an overall carbon intensity (CI) for the fuel mix they supply to California. The standards are set on an annual basis and become more stringent from 2011 to 2020, ultimately resulting in an average 10 percent reduction in the carbon intensity of most transportation fuel sold in California by 2020. The proposal does not specify which combination of transportation fuels the regulated parties must provide to comply with the standards, and it does not limit the CI of any particular fuel. However, to meet the LCFS, the fuel mix will need to include alternative fuels that have lower CI than traditional fuels.

For the economic analysis of the LCFS, staff estimated the costs of producing the petroleum-based fuels—gasoline and diesel—and the costs of producing the lower carbon-intensity (lower-CI) transportation fuels that could be used in combination with petroleum fuels to meet the LCFS. The costs for the lower-CI fuels included the capital costs for building new fuel production facilities, the operating costs associated with the facilities, and the distribution costs of the products. In additional to liquid fuels, such as ethanol and biodiesel, lower-CI fuels that were assessed included electricity, hydrogen, and compressed natural gas (CNG).

Once staff estimated the overall production and distribution costs of the lower-CI fuels, staff applied them to eight compliance scenarios—illustrative examples of possible compliance pathways. They include five scenarios for gasoline and its substitute fuels, and three for diesel fuel and its substitute fuels. Each of these scenarios includes an assumed mix of lower-CI fuels that satisfies the LCFS reduction targets for the overall fuel mix. Chapter VI discusses the scenarios in more detail.

Staff then evaluated the savings that would occur in each scenario due to the avoided cost of buying the traditional fuels that were displaced by the lower-CI transportation fuels. Next, for each of the compliance scenarios, staff estimated the net cost and/or savings, and calculated the cost effectiveness, defined as net LCFS regulation costs (or savings), in dollars, divided by the carbon dioxide equivalent emissions reduced, in metric tons. Finally, staff estimated how the fuel procurement costs or savings incurred by fuel providers under the proposed LCFS might be reflected in fuel prices and thereby affect businesses, consumers, and government agencies.

1. Gasoline and Diesel Costs

To perform a cost analysis of the proposed regulation, staff first projected the cost of producing and distributing (i.e., getting the fuel to the station) the traditional petroleum-based fuels that would be displaced by alternative fuels needed to comply with the LCFS. Estimates of the future cost of producing gasoline and diesel are highly dependant on the future price of crude oil.

For this analysis, staff used forecasts of prices for crude, gasoline, and diesel that are included in the Energy Commission's document "Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report (IEPR)(82)." To be consistent with the assumptions used in preparing the AB 32 Scoping Plan, approved by the Board in December 2008, staff used the "high case" values in the report. To estimate the production and distribution cost of gasoline and diesel fuels, staff subtracted the appropriate federal, state, and local taxes from the retail prices.

Table VIII-1 presents the referenced estimates for crude prices and ARB staff's estimates of the cost of producing and distributing gasoline and diesel, based on those crude prices. The crude prices forecasts were based on the Energy Information Administration's (EIA) crude price estimates at the time. Recently, EIA published an updated forecast of crude prices: for the period of 2010 – 2020, EIA estimates crude prices at $78 - $116/bbl for their reference case, which is their mid-range estimate of future prices. This is much higher than the $66 - $88/bbl "high case" estimate included in EIA's previous estimate.

Currently, Energy Commission staff is estimating crude prices and associated California retail fuel prices for their 2009 IEPR, taking into account this recent EIA forecast. For the purpose of the LCFS economic analysis, staff used the 2007 IEPR estimates to be consistent with the AB 32 Scoping Plan. Staff recognizes that the higher, more recent crude price estimates would enhance the cost effectiveness of the proposed LCFS regulation.

Table VIII-1
Estimated Crude Prices and Associated Costs to Produce and Distribute Gasoline and Diesel (2007 dollars)

Year	Crude Price ($/bbl)	Cost of Gasoline Production and Distribution[1] ($/gal)	Cost of Diesel Production and Distribution[1] ($/gal)
2010	$66	$2.42	$2.48
2011	$68	$2.46	$2.53
2012	$70	$2.51	$2.57
2013	$73	$2.57	$2.63
2014	$76	$2.65	$2.71
2015	$79	$2.70	$2.77
2016	$81	$2.76	$2.82
2017	$83	$2.80	$2.86
2018	$84	$2.84	$2.90
2019	$86	$2.88	$2.95
2020	$88	$2.92	$2.99

1 Cost excludes federal, state, and local taxes.

2. Lower-CI Fuel Production and Distribution Costs

a. General Discussion

The next step in the economic analysis of the LCFS was to estimate the production and distribution cost of the lower-CI fuels, including liquid biofuels (ethanol and biodiesel) and other lower-CI fuels (hydrogen, electricity and CNG) that will displace the traditional petroleum-based fuels.

Lower-CI Liquid Biofuels:

The production and distribution costs for the lower-CI liquid biofuels included the capital costs for building the fuel-manufacturing facility, the operating or production costs to produce the specific fuel, the costs for purchasing the feedstock material for the fuel, and the costs for storing, transporting, and distributing the fuel. Staff adjusted the costs, where applicable, with a co-product credit if the fuel-production process had other economic benefits, such as creating material for other products or providing steam for electrical generation at the facility.

While some of these liquid biofuels are commercially available—corn ethanol, sugarcane ethanol, biodiesel from crops, animal fats, and grease—other lower-CI liquid fuels are in an earlier stage of development. Significant examples of this are cellulosic ethanol and hydrocarbons from algae and green wastes.

To estimate the overall production cost for these biofuels, staff relied on documentation from several sources, including: the National Renewable Energy Laboratory (NREL); the United States Department of Agriculture (USDA); the Antares Group (Antares); Iowa

State University; Kansas State University; Biomass and Bioenergy Journal; Bioresource Technology Journal; and Sparks Companies Inc. Staff discusses the specific utilization of these resources within the cost subcategories below. In order to compare the lower-CI fuel costs to traditional fuel costs, staff converted cost estimates of ethanol biofuels to gallons of gasoline equivalent (gge), which took into account the lower energy content of ethanol as compared to gasoline. The energy content of biodiesel was assumed to be approximately equal to that of traditional diesel, so staff made no adjustments to those cost estimates. (See Appendix G for gge conversion calculations.)

<u>Other Lower-CI Fuels:</u>

In addition to the liquid biofuels, staff estimated the cost of producing and distributing three other lower-CI fuels: hydrogen, electricity, and CNG. As with the liquid biofuels, staff converted these costs to gge. In addition, staff adjusted those values to recognize the difference in energy efficiency of the cars in which these fuels are used. This was done by dividing the gge-adjusted cost numbers by the applicable Energy Economy Ratio (EER), which compares the energy economy of an alternative fuel vehicle to a conventional gasoline or diesel vehicle.

For example, an electricity cost of $0.09/ kilowatt-hour (kW-hr) converts to $2.89/gge on an energy content basis. The EER for an electric vehicle is estimated to be 3.0 (i.e., an electric vehicle is three times more efficient than a conventional gasoline-fueled vehicle in converting the energy in the fuel into energy used to power the vehicle). The gge value would then be adjusted by dividing $2.89 by three—$0.96/gge, EER adjusted.

Electricity costs were based on electricity tariffs from Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and the Los Angeles Department of Water and Power (LADWP). Hydrogen costs were based on data provided by the Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies. CNG cost estimates were based on available data provided by the Energy Commission in the 2007 State Alternative Fuels Plan(1), which was required by AB 1007 (Pavley, 2005).

b. Capital Costs

Staff estimated the capital costs of commercial biofuel production plants based on available information. For some biofuels, staff relied on capital cost estimates conducted by NREL, Antares(18), Tijmensen(83), Haas(84), Zhang(85) and Gallagher(86). For example, NREL, Tijmensen(83), and Haas(84), using the ASPEN Plus model, conceptually designed lignocellulosic, FAME, and Fischer-Tropsch (F-T) biodiesel facilities. ASPEN Plus is a process modeling program tool for conceptual design, optimization, and performance monitoring for specialty chemicals, metals, minerals, and coal power industries. The NREL studies also engaged engineering firms that have expertise in this subject matter.

Also, the NREL Processing Engineering Team developed a database of primary information on the equipment needed for such facilities. This database contains information on anticipated costs, reference year, scaling factor, design information, and back-up cost referencing. Table VIII-2 presents an example of some of the specific pieces of equipment and the estimated costs in the NREL ASPEN Plus database needed for a biofuel plant producing 25 million gallons per year (MGY).

Table VIII-2
Estimated Costs for Some Biofuel Plant Equipment from NREL Using ASPEN-Plus Database (NREL, 1999)

Equipment	Cost
Hopper Feeder	$41,700
Pretreatment Feeder	$122,000
Beer Column Reflux Drum	$22,400
Aerobic Digester	$600,000
Sulfuric Acid Storage Tank	$54,400
Cooling Tower System	$1,630,000

For dry-mill corn ethanol, Gallagher(86) used a mathematical model to estimate the capital costs. The wet-mill corn ethanol capital cost is based on data from Whims(87), while the fatty acid to hydrocarbon (FAHC) biodiesel is based on current and planned facilities for ConocoPhillips, Neste Oil, and Petrobras. (See Chapter III for more details on these facilities.)

When estimating the capital cost of various sizes of biofuel production facilities, the size of the individual equipment can be scaled up or down using published scaling factors. These scaling factors take into account economy of scale, which asserts that an increase in processing capacity can be achieved with a smaller percentage increase in capital cost.

The economy of scale is expressed as follows(88):

$$\text{New Capital Cost} = \text{Original Capital Cost} \times (\text{New Capacity Size/Old Capacity size})^{\text{scaling factor}}$$

As an example, if a 25 MGY facility costs $174 million to build, a 50 MGY plant would cost $240 million to build, applying an economy-of-scale factor of 0.6. Scaling factors typically range from 0.6 to 0.8. For our analyses, staff used a scaling factor of 0.6, which is consistent with the studies that staff analyzed.

To estimate the annual capital recovery cost, staff used a capital recovery factor of 14.90 percent, based on an eight percent real discount rate per year with a capital recovery period of 10 years. The economic analysis for this regulation evaluates the private compliance costs that companies would face, so these assumptions are intended to reflect the risk in investing in new biorefinery technologies—the “cost of financing.” The economic analysis for the AB 32 Scoping Plan was designed to reflect societal costs, and used a five percent real discount rate and the expected life of the equipment, which was typically assumed to be 20 years. Sensitivity analyses for several of the scenarios have also been conducted using a five percent and ten percent real discount rate. (See Section E.)

The associated annualized capital recovery cost can be determined according to the following equation:

Capital Recovery Cost ($/Gal) = (Capital Cost x Capital Recovery Factor)/Plant Capacity

For the 25 MGY biofuel facility above, its capital cost of $174 million will result in an annual capital recovery of $26 million (eight percent interest for 10 years). For the 25 million gallons per year, that translates into $1.04/gal of fuel produced.

The estimated capital costs for ethanol varies between $0.31/gge and $1.37/gge. The corn dry-mill facility has the least estimated capital costs because the process is straightforward and highly commercial; the wood chips lignocellulosic ethanol facility has the highest estimated capital costs due to feedstock-handling and multistep processing. Because there are no lignocellulosic ethanol facilities in operation, the estimated costs for these facilities in the documents on which ARB relied (e.g., NREL reports) include some level of uncertainty.

For biodiesel, the range of estimated capital costs per gallon varies between $0.09/gal and $2.43/gal. The estimated capital cost is least for a fatty acid methyl esters (FAME) biodiesel plant because the process operates at relatively lower temperatures and pressures with high conversion rates and low reaction times. Conversely, the highest estimated capital cost is for the F-T diesel plant due to multistep processing, including gasification of solid feedstocks and catalytic conversion to hydrocarbons. In general, the more processing that is necessary to produce the biofuel, the higher the capital costs. (See Chapter III for a discussion on the biofuel technologies.)

Staff also included the cost of best available control technology (BACT) to reduce air emissions from these biorefineries. Staff estimated the cost for BACT at approximately $2 million per plant. Using a capital recovery factor of 14.90 percent, this translates to $0.006/gal for a 50 MGY plant. (See Chapter VII for a more detailed discussion.)

c. Production Costs

The costs to produce the biofuels include fixed and variable costs. Fixed costs include annual operating and maintenance labor, taxes, and insurance, while variable costs include utilities, non-feedstock raw materials (sulfuric acid, lime, nutrients, etc.), and waste disposal. To estimate the fixed and variable costs for the various biofuels, staff analyzed studies that utilized ASPEN Plus, a United States Department of Agriculture ethanol cost-of-production survey(89), and a compilation of studies.

For ethanol, the production cost of lignocellulosic ethanol from corn stover is higher than wood chips because of assumed higher labor expense. For biodiesel, the range of estimated production costs per gallon varies between $0.27/gal and $1.66/gal. The estimated production cost is least for a fatty acid to hydrocarbon (FAHC) biodiesel plant because the hydrotreating process results in a product that needs little further processing. Conversely, the highest estimated production cost is for the F-T diesel plant due to the multistep processing described above.

Based on an Aspen Plus analyses conducted by NREL(90) and Haas(84), energy input accounts for 15 to 20 percent of the total production cost. These fuel-related costs include gasoline used as denaturant for ethanol, diesel, and electricity. For the LCFS economic analysis, staff raised the production costs of the liquid biofuels by 20 percent in the scenarios when higher crude prices are assumed. For example, if crude prices were to double, staff would raise the production costs of the liquid biofuels by 20 percent.

For CNG, staff used Energy Commission retail price estimates for 2010-2020(91), subtracting a 10 percent profit margin to estimate production costs. Staff did not adjust electricity costs.

d. Feedstock Costs

The feedstock cost per gallon of ethanol is calculated as follows:

Feedstock Cost per Gallon = Price of Feedstock/ Ethanol Yield of Feedstock

For example, if the cost of corn is $4.00 per bushel (approximately the average 2009 future prices listed in February 2008) and the dry-mill ethanol yield is 2.72 gallons of ethanol per bushel, then the feedstock cost is $1.47/gal, or $2.18/gge. This cost does not take into account the co-product credit which is discussed in the next section.

The estimated feedstock costs for ethanol vary between $0.00/gge and $2.13/gge. Staff estimated the cost of municipal solid waste (MSW) as a feedstock at zero. (MSW here refers to the grass, wood, and paper portion of municipal solid waste.) Whereas some reports that staff reviewed asserted a negative cost for MSW because of avoided tipping fees at the landfills, most of California's green waste does not go to landfills. AB 939(92) required a 50 percent reduction of material being sent to California landfills by 2000, which resulted in segregation of paper and plant materials. Typically the plant material is used to make compost, and the paper is recycled. Staff assumes these materials can be delivered to biorefineries for the same cost as delivering them to recycling or compost facilities, hence the cost-neutral feedstock price. Conversely, the highest estimated feedstock cost is for wet-mill corn ethanol due to the higher commodity prices of corn and a lesser yield than with the dry-mill process.

Similarly, for biodiesel, the range of estimated feedstock costs varies between $0.68/gal and $2.62/gal. The feedstock cost is least for F-T diesel since relatively inexpensive wood chips are used as feedstock. The highest estimated biodiesel feedstock cost is for an FAME process using soybean oil.

As with the production costs at the biorefineries, the cost of crude oil also affects the cost of biorefinery feedstocks. According to "Ethanol Production Using Corn, Switchgrass, and Wood; Biodiesel Production Using Soybean and Sunflower" (93), 20 to 35 percent of the cost of growing corn or soybeans is related to fuel costs. These costs include diesel, gasoline, fertilizer, electricity, and transport costs. Labor, most nonpetroleum chemicals, and capital recovery for machinery are fixed production costs not affected by crude prices.

To be conservative, staff raised the feedstock costs of the liquid biofuels by 35 percent in the LCSF economic analysis when higher crude prices are assumed. For example, if crude prices were to double, staff would raise the feedstock costs of the liquid biofuels by 35 percent.

The cost of transporting a feedstock to a biorefinery is included in the feedstock prices. Staff assumed a feedstock is transported within 50 miles of a biorefinery.

In addition to the liquid biofuels, staff evaluated the feedstock costs for other non-liquid lower-CI fuels that are expected to be used in greater quantities to meet the LCFS. Hydrogen may be produced in a variety of ways, currently the most common by steam-methane reforming (SMR). The methane can be produced from natural gas or biogas from landfills. Furthermore, hydrogen and methane for SMR can be co-produced from pyrolysis or gasification of solid waste, such as biomass or coal. Hydrolysis is another technology for producing hydrogen. Although a net energy consumer, hydrolysis can be powered by renewable sources of energy, such as wind and solar. Staff estimated the feedstock cost of hydrogen production, based on steam-methane reforming of natural gas, to be $0.70/gge, EER adjusted[61].

According to the Energy Commission, the retail price of CNG is estimated to follow a range of $1.81 to $2.04/gge over the 2010 – 2020 compliance periods. Staff assumed a 10 percent profit margin; therefore, staff calculated the average cost of CNG at $1.81 to $2.04/gge, EER adjusted. These values were converted to diesel gallon equivalent (DGE) in the diesel scenario calculations.

Table VIII-3 summarizes the commodity prices and yields that staff used to determine the per-gallon feedstock costs for the liquid alternative transportation fuels.

[61] Senate Bill 1505 (Lowenthal, 2006) directed the ARB to develop a regulation to set environmental standards for hydrogen fuel produced/dispensed for transportation use in California; therefore, hydrogen production cost estimates may be impacted by future regulatory requirements.

Table VIII-3
Commodity Prices (2007 Dollars) and Yields

Commodity	Price	Reference	Yield	Reference
Corn (dry mill)	$3.77/bu	CNNMoney, 2008(94)	2.72 gal/bu	CA-GREET, 2009(47)
Corn (wet mill)	$3.77/bu	CNNMoney, 2008(94)	2.62 gal/bu	CA-GREET, 2009(47)
Corn Stover	$38/ton	LafayetteOnline, 2008(95)	80.6 gal/ton	Antares(b), 2008(18)
Wood Chips (Cellulosic)	$29/ton	NREL, 2008(96)	90.2 gal/ton	Antares(b), 2008(18)
Wood Chips (FT)	$29/ton	NREL, 2008(96)	42 gal/ton	Antares(b), 2008(18)
Soybean Oil	$0.34/lb	CBOT, 2009(97)	7.6 lbs/gal biodiesel	Antares, 2008(18)
Yellow Grease (FAME)	$0.11/lb	Tribe, 2008(98)	249 gal/ton	Antares(b), 2008(18)
Yellow Grease (FAHC)	$0.11/lb	Tribe, 2008(98)	250 gal/ton	Antares(b), 2008(18)
Municipal Solid Waste (vegetation and paper)	$0.00/ton	Staff Estimated Cost	86 gal/ton – paper 70 gal/ton - vegetation	Antares(b), 2008(18)

e. Co-Product Credits

The production of some biofuels generates significant co-product benefits. For example, with a dry-mill corn ethanol plant, the solids remaining after distillation are called distiller's grains and solubles (DGS). These can be dried (DDGS) or used wet (WDGS) with minimal energy to prepare for use as feed. Both DDGS and WDGS are used as an animal feed supplement, typically for cattle and swine. This DDGS and WDGS in effect displaces a portion of the corn that, if not used for ethanol production, could have been used as animal feed.

The price of DGS prices varies with corn prices; however, the cost is also influenced by the cost of soybean meal, a competitive livestock feed supplement. According to the CA-GREET model, a bushel of corn produces 2.72 gallons of ethanol and 14.5 pounds of DDGS. Recent prices for corn and DDGS were $3.58/bushel(99) and $150/ton(100), respectively, which would value the DDGS at $1.09/bushel, a 30 percent cost recovery of the purchased corn. To simplify the economic analysis, staff assumed a 30 percent cost recovery for corn processed at dry-mill ethanol plants.

A wet-mill corn ethanol plant produces a number of valuable by-products, including corn gluten, corn gluten meal, and corn oil. For this reason, the co-product credit for a wet mill is higher than for a dry mill. According to Whims(87), the co-product value is estimated to represent about 53 percent of the purchase price of corn.

According to an NREL study, a co-product credit for lignocellulosic ethanol can be realized by using excess steam to generate electricity, which may be sold to the grid.

This is also true for Fischer-Tropsch (F-T) diesel, which also produces naphtha as a co-benefit(18).

For the lignocellulosic ethanol process, staff relied on an NREL analysis in which the plant operates 8,000 hours per year, generating approximately 18 MW of electricity, of which half is consumed on site(90). The excess electricity equates to 70,400 MW-Hr, which is then sold to the grid at a wholesale price of $0.054/kW-Hr.

For the F-T diesel process, the electricity generated is approximately 560 kW-Hr per barrel of F-T liquids produced, with the excess sold to the grid at a price of $0.054/kW-Hr. Naphtha represents about 30 percent of the total liquid product and for this analysis is sold at a price of $1.50 per gallon(18).

The FAME biodiesel co-product is crude glycerin, which can be sold to a chemical manufacturer. FAHC co-products are light hydrocarbons that can be further processed to produce gasoline. Staff estimated the value of glycerin at approximately seven percent of the feedstock cost(84), which is sold at a price of $0.17 per gallon. The light hydrocarbons from the FAHC process represent approximately 3.5 to 4.4 weight percent of the feedstock, which is sold at $1.04 per gallon.

Table VIII-4 lists the co-products that can be created from producing certain biofuels and the estimated values for these co-products that staff used in the lower-CI fuel cost calculations.

Table VIII-4
Co-Products from Biofuel Production and Their Estimated Values

Process	Feedstock	Co-Product(s)	Yield	Estimated Value
Dry Mill Fermentation	Corn	DDGS	14.5 lbs/bushel	30% of corn price
Wet Mill Fermentation	Corn	Corn Gluten Corn Gluten Meal Corn Oil	11.4 lbs/bushel 3 lbs/bushel 1.6 lbs/bushel	53% of corn price for all co-products
Lignocellulosic Fermentation	Corn Stover Wood Chips MSW (Grass, Wood, and Paper)	Electricity	Varies	Wholesale price estimated at $0.054/kW-hr
Fischer-Tropsch Diesel	Wood Chips	Electricity Naphtha	Varies 30% liquid yield	$0.054/kW-hr $1.50/gal
FAME Biodiesel	Yellow Grease	Glycerin	7% of feedstock	$0.17/gal
FAHC Diesel	Yellow Grease	Light Hydrocarbons	3.5 – 4.4 wt % of feedstock	$1.04/gal

f. Storage, Transport, and Distribution Costs

Staff used the U.S. EPA document entitled “Impact Analysis: Renewable Fuel Standard Program(19),” an analysis of the first federal RFS, to estimate the storage, transport, and distribution costs of the biofuels. According to the RFS document, the average state-by-state freight cost for ethanol is approximately $0.21/gal (from the Midwest to California by rail). Furthermore, U.S. EPA estimated that the ethanol distribution and storage infrastructure under RFS1 will be approximately $350 million for 2.77 billion gallons of ethanol. This equates to an annual capital cost recovery of $45.6 million, which in turn translates to approximately $0.02/gal for storing and distributing ethanol.

Therefore, staff estimated the cost for storage, transport, and distribution of ethanol biofuels from out-of-state at $0.23/gal, or $0.34/gge for ethanol. According to a California biorefinery, the cost to transport ethanol within California (Northern California to Southern California) by truck is estimated to be $0.20/gal to $0.30/gal(101). Therefore, staff used the same cost for storage, transport, and distributing for both out-of-state ethanol biofuels and ethanol produced within the State. Staff assumed similar infrastructure and cost for biodiesels, but did not convert them to gges.

According to data provided by the Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies the storage, transport, and distribution costs for hydrogen is $0.57/gge, EER adjusted(102).

g. Fuel Dispensing Costs

Conventional gasoline or RFG can contain up to 10 percent ethanol (E10) by volume and be used in any gasoline vehicle. E10 needs no infrastructure as all storage tanks and dispensing equipment can accommodate up to E10. However, E85 (nominally 85 percent ethanol and 15 percent gasoline) can only be used in vehicles designed for its use. Today, these are flexible-fuelled vehicles (FFVs) which can accommodate from E0 (gasoline with no ethanol) to E85. Current gasoline equipment at service stations cannot accommodate E85.

The estimated storage, transport, and distribution costs accounted for getting the fuel to the retail station. To complete a “well-to-wheels” analysis, staff estimated the cost of installing the infrastructure at the retail stations required to fuel the vehicles. Staff is assuming there will be two gasoline products on the market: E10 and E85. E85 will become more prominent when the total volume of ethanol needed to meet the average CI levels set by the proposed LCFS in 2015 and beyond cannot be satisfied by E10 alone. Should U.S. EPA allow E15 or E20 fuels, the additional volume of ethanol needed to meet the LCFS may be provided by these products instead, which will reduce the need for E85.

E85:

The necessary E85 infrastructure at an existing gasoline dispensing facility or service station includes a 10,000 gallon tank, one dispenser with two nozzles, and other piping. The estimated costs in Table VIII-5 are based on a recent E85 installation at an existing service station(103).

Table VIII-5
Cost of Installing E85 Dispensing Infrastructure per Existing Service Station (2007 dollars)

Equipment & Parts	Installation	Permits	Soil Disposal & Testing	Total
\$72,000	\$87,000	\$5,000	\$8,000	\$172,000

Hydrogen:

The capital cost of a hydrogen station ranges from \$250,000 for a 10 kg H_2/day mobile refueling unit to \$5 million for a 1,000 kg H_2/day steam-methane reformer station(104). For the economic analysis, staff used a 1,000 kg H_2/day liquid delivery system for public fleets, with an estimated capital cost of \$2.7 million per fueling station. Assuming annual sales of 173,000 kg H_2 (47 percent capacity factor), staff estimated that the cost of a hydrogen station adds \$3.60/per kg sold, or \$1.57/gge, EER adjusted.

CNG:

Staff assumed increased throughput of CNG would require both expanding existing CNG fueling stations (adding infrastructure for increased capacity) and building new stations. Staff assumed the new CNG stations would be added to existing truck stops along major freeways. Staff assumed one new station would be built for every five existing stations retrofitted, resulting in 20 percent more stations equipped for CNG fueling. New infrastructure at an existing CNG station includes a dispenser, compressor, and dryer. Staff assumed an additional dispenser and compressor at the new stations so that two vehicles could be services simultaneously. A new station includes storage tanks, two dispensers, two compressors, and a dryer(105, 106). The costs in Table VIII-6 are based on estimates from a gas utility company[62].

[62] Phone calls with Sempra and equipment manufacturing company, December 2008.

Table VIII-6
Estimated Cost of Upgrading Existing or Creating New CNG Fueling Station (2007 dollars)

Facility Type	Dispenser with two hoses	400 CFM Compressor with Installation	New Dryer	(Storage, dispensing, compressing)	Total
Existing CNG Station	$57,400	$239,100	$76,500		$373,000
New CNG Dispenser at Existing Truck Stop	$57,400	$239,100		$717,500	$1,014,000

Electricity:

For electricity, staff estimated the costs based on electricity tariffs from Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and the Los Angeles Department of Water and Power (LADWP). Table VIII-7 presents the specific tariff schedules that staff referenced.

Table VIII-7
Electricity Tariffs Used in LCFS Economic Analysis

Load-Serving Entity	Tariff Schedule	Description
PG&E	R: E-9 (PGE9)	Experimental Residential Time-of-Use Service for Low Emission Vehicle Customers
	C: E-19 (PGE19)	Medium General Demand-Metered TOU Service
SCE	R: TOU-EV-1 (SCEEV1)	Domestic Time-of-Use Electric Vehicle Charging
	C: TOU-EV-4 (SCEEV4)	General Service Time-Of-Use Electric Vehicle Charging - Demand Metered
LADWP	R: R-1 Rate B (LADWPR1)	Residential TOU with Electric Vehicle Credit
	C: A-2 Rate B (LADWPA2)	General Service TOU with Electric Vehicle Credit

R = Residential, C = Commercial

Staff assumed that the owners of the plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs) would predominately recharge their vehicles during off-peak times. Therefore, for residential customers (light-duty vehicles), staff assumed $0.09 per kilowatt-hour (kW-hr). For commercial customers (medium-duty and heavy-duty vehicles), staff assumed $0.12/kW-hr. Converting to gges based on energy content, these rates are $2.89/gge ($0.96/gge, EER adjusted) and $3.85/gge ($1.28/gge, EER adjusted), respectively. To account for metering charges, staff rounded up these costs to $1.00/gge, EER adjusted, for gasoline scenarios and $1.33/gge, EER adjusted, for diesel scenarios.

h. Summary of Lower-CI Fuel Costs

The costs for each fuel are presented below in Table VIII-8. Staff assumed that these are 2010 costs in 2007 dollars. Tax credits were not included in this table, but are included in the economic analysis as discussed in the next subsection. Furthermore, research and development costs for the lower-carbon-intensity alternative transportation fuels are not included in these costs.

Table VIII-8
Lower-CI Fuel Costs ($/gge, except for biodiesel [$/gal])

Fuel	Feedstock	Capital Cost	Production Cost	Feedstock Cost	Co-Product Credit	Storage Transport Distribution[1]	Total	Reference
Ethanol	Corn (Dry Mill)	0.31	0.81	2.05	-0.61	0.34	2.90	USDA 2002(89), and Gallagher, 2005(86)
Ethanol	Corn (Wet Mill)	0.65	0.89	2.13	-1.14	0.34	2.87	Whims, 2002(87)
Brazilian Ethanol	Sugarcane[2]	0.77	0.75	0.44	0.00[3]	0.67[4]	3.26[5]	USDA, 2006(107)
Lignocellulosic Ethanol	Corn Stover	1.22	1.15	0.70	-0.22	0.34	3.19	NREL, 2000(90)
Lignocellulosic Ethanol	Wood Chips	1.37	0.66	0.47	-0.14	0.34	2.70	NREL, 1999(88)
Lignocellulosic Ethanol	Municipal Solid Waste	1.35	0.62	0.00		0.34	2.31	Fulcrum, 2008 (108) Tomkinson(109)
Fischer-Tropsch Biodiesel	Wood Chips	2.43	1.66	0.68	-1.25	0.22	3.74	Tijmensen, 2002(83), and Antares, 2008(18)
FAME Biodiesel	Soybean Oil	0.12	0.36	2.62	-0.17	0.22	3.15	Haas, 2006(84)
FAME Biodiesel	Yellow Grease	0.09	0.67	0.85	-0.17	0.22	1.66	Zhang, 2003(85)
FAHC Biodiesel	Yellow Grease	0.30	0.27	0.84	-0.06	0.22	1.57	Antares, 2008(18)
Hydrogen	Natural Gas			0.70[6]		0.57[6]	1.26[6]	Hydrogen, 2008(102)
CNG	Natural Gas						1.81[6]	CEC, AB-1007 (92)
Electricity	Grid						1.00 g[6] 1.33 d[6]	PG&E, SCE, LADWP, 2008

1 Imported ethanol transported by rail; intrastate ethanol transported by truck.
2 Assumed the conversion of sugarcane to ethanol is the same process as conversion of corn (dry mill) to ethanol but more capital intensive due to grinding sugarcane into flour.
3 Co-benefit of using bagasse as fuel is included in the production cost.
4 Assumed transportation cost from plant to port $0.21/gal (RFS), port cost $0.10/gal and transportation from Brazil to U.S. $0.14/gal.
5 Added tariff of $0.54/gal and 2.5% ad valorem tax.
6 Local dispensing costs not included for hydrogen, CNG, and electricity. These costs are addressed in 2. g. Values take into account the Energy Economy Ratio (EER) of the vehicles into which the fuels are dispensed (FCVs = 2.3; PHEVs and BEVs = 3.0; CNG HD vehicles = 0.9)
g = gge cost of electricity for gasoline scenarios; d = gge cost of electricity for diesel scenarios

For the gasoline scenarios, staff used several corn-based ethanol sources, such as “Midwest corn,” California low-CI,” and “federal new renewable.” “Midwest corn” is based on existing corn ethanol facilities—85 percent from dry milling and 15 percent from wet milling—and is assumed to have a carbon intensity of 99.4 g CO2/MJ. "California low-CI" ethanol assumes a dry-mill process with a carbon intensity of 80.7 g CO2/MJ. "Federal new renewable" ethanol also assumes a dry mill process and has a carbon intensity of 76.7 g CO2/MJ.

As discussed above, staff adjusted the production costs and feedstock costs of the liquid biofuels as crude prices varied. Table VIII-9 below shows the cost impacts of those adjustments.

Table VIII-9
Estimated Impact of Changes in Crude Prices on Lower-CI Fuel Costs ($/gge, except for biodiesel [$/gal])[1]

		Ethanol						Biodiesel				
Year	Projected Crude Price ($/bbl)	Midwest Corn (dry mill)	Midwest Corn (wet mill)	Lignocell. (wood chips)	Sugarcane (Brazil)	Lignocell. (corn stover)	Green Wastes	FAME (Soybean Oil)	FAME, Yellow Grease (waste grease)	F-T (Wood chips)	FAHC (Yellow Grease)	CNG[2]
2010	$66	$2.87	$2.87	$2.70	$3.25	$3.19	$2.31	$3.15	$1.66	$3.74	$1.57	1.81
2011	$68	$2.89	$2.90	$2.71	$3.26	$3.20	$2.31	$3.18	$1.67	$3.76	$1.58	1.83
2012	$70	$2.91	$2.92	$2.72	$3.27	$3.22	$2.32	$3.21	$1.68	$3.77	$1.59	1.86
2013	$73	$2.94	$2.96	$2.73	$3.28	$3.23	$2.32	$3.24	$1.70	$3.79	$1.60	1.87
2014	$76	$2.97	$3.00	$2.74	$3.29	$3.26	$2.33	$3.29	$1.72	$3.82	$1.62	1.90
2015	$79	$2.99	$3.03	$2.75	$3.30	$3.27	$2.33	$3.32	$1.73	$3.84	$1.63	1.92
2016	$81	$3.01	$3.05	$2.76	$3.31	$3.28	$2.33	$3.35	$1.75	$3.85	$1.64	1.96
2017	$83	$3.03	$3.07	$2.77	$3.32	$3.29	$2.34	$3.37	$1.75	$3.87	$1.65	1.97
2018	$84	$3.04	$3.09	$2.77	$3.32	$3.30	$2.34	$3.39	$1.76	$3.88	$1.65	1.99
2019	$86	$3.06	$3.11	$2.78	$3.33	$3.31	$2.34	$3.41	$1.77	$3.89	$1.66	2.02
2020	$88	$3.07	$3.13	$2.78	$3.34	$3.32	$2.35	$3.43	$1.78	$3.90	$1.67	2.04

1 All lower-CI fuel costs increase annually; however, slight annual differences may not be apparent due to rounding.
2 $/gge, EER adjusted. CNG cost increases were based on retail price estimates in Energy Commission's 2007 State Alternative Fuels Plan and are not directly related to crude prices.

i. Alternative-Fuel Tax Incentives

There are a number of tax incentives for alternative fuels to encourage their production by making them more economically competitive with petroleum-based fuels. Increasing production of domestically-supplied lower-CI fuels will assist the U.S. with improving energy independence and security and with improving the environment. Blenders, producers, and sellers of some biofuels will receive tax credits, which will affect the profit margin or the selling price of biofuels. Staff reduced the overall cost of production of the lower-CI fuels that were presented in Table VIII-8 by the amount of the tax incentives, where applicable. The credits are assessed on a gallon of ethanol or biodiesel blended or produced and on the volume of CNG sold. Although some incentives could expire in the near future, staff assumed the incentives would be extended, as has been the case with incentives that had recently expired. A discussion of the tax credits is presented below.

Ethanol and Biodiesel Blenders:

The American Jobs Creation Act of 2004 created a new excise tax credit system for ethanol and biodiesel blenders. As of January 1, 2005, the federal tax credit was $0.51 per gallon of pure ethanol blended, $1.00 per gallon of agricultural biodiesel (derived from virgin oils), and $0.50 per gallon of "waste grease" biodiesel (derived from vegetable oils and animal fats)(110). The Food, Conservation, and Energy Security Act of 2008 (2008 Farm Bill) reduced the ethanol credit to $0.45 per gallon of ethanol blended, effective January 1, 2009(111). The Emergency Economic Stabilization Act of 2008 eliminated the disparity in credit for biodiesel and agri-biodiesel (now providing $1.00 per gallon of biodiesel blended), and extended the credit through the end of 2009(112).

Cellulosic Ethanol Producers:

The 2008 Farm Bill created a new cellulosic biofuels production tax credit of $1.01 per gallon produced. This credit is effective January 1, 2009, through December 31, 2012(111).

Small Ethanol and Agri-Biodiesel Producer:

The Omnibus Budget Reconciliation Act of 1990, revised by the American Jobs Creation Act of 2004 and the Energy Policy Act of 2005, provides a tax credit to small ethanol producers of $0.10 per gallon for the first 15,000,000 gallons produced. A small producer is defined as a facility that produces less than 60 million gallons of ethanol per year(113). The 15 million gallon limitation does not apply to cellulosic ethanol. Thus, the credit may be claimed for cellulosic ethanol produced in excess of 15 million gallons(111).

The small agri-biodiesel producer credit was part of the Energy Policy Act of 2005 and has similar credits, facility size restrictions, and production limitations as those imposed on the small-ethanol-producer tax credit(113). Staff did not include any tax credit for either the small ethanol or agri-biodiesel blenders in the cost analysis because it is uncertain how many future ethanol plants in the State would qualify for these credits.

Ethanol Tariff:

To keep from incenting the production and importation of foreign ethanol, ethanol imported into the United States is subject to a 2.5 percent ad valorem tariff (a duty levied on an imported item based on the item's value) as well as a secondary tariff of 54 cents per gallon of ethanol imported from non-Caribbean Basin countries (approximately 60 cents/gallon total for sugarcane ethanol). The secondary tariff was first placed on foreign-produced ethanol by Congress in 1980. The 2008 Farm Bill extended this tariff through 2010.

<u>CNG Sellers:</u>

The Safe, Accountable, Flexible, Efficient Transportation Equity Act, signed in 2005, created a 50 cents per gasoline-gallon-equivalent tax credit for CNG sold as a motor vehicle fuel(114).

3. Baseline Determination for the Compliance Scenarios

Staff created a baseline scenario for the LCFS regulation from which the emission reductions and cost effectiveness of the LCFS regulation can be estimated. The baseline scenario reflects the successful implementation of the Scoping Plan measures that impact the amount of transportation fuels and resultant GHG emissions expected in California between 2010 and 2020. These regulations and programs include: the ARB Zero Emission Vehicle (ZEV) regulation, the federal Corporate Average Fuel Economy (CAFE) program, the Pavley regulation, and the federal Renewable Fuel Standard (RFS). For the purpose of determining compliance with the LCFS, the initial year is considered 2010; staff extrapolated the baseline for years 2011 – 2020.

The ARB ZEV regulation will impact the State's future mix of transportation fuel. The Board first adopted the ZEV regulation in 1990 as part of the Low Emission Vehicle Program. Since then, the Board has made modifications to the regulation, the most recent in March 2008. The goal has been to have zero-emission technologies on the roads on a mass scale as soon as possible, considering the state of technology, market factors, economic impact, and environmental benefits. ARB staff estimates that the number of advanced-technology vehicles using electricity or hydrogen as a fuel—battery electric vehicles (BEVs), plug-in hybrid vehicles (PHEVs), or fuel cell vehicles (FCVs)—will increase to about 560,000 vehicles by 2020. This volume is consistent with the penetration schedule in the 2008 ARB ZEV regulation. Staff considered the deployment of this number of ZEV vehicles as part of the baseline analysis. Staff also considered other scenarios with up to two million advanced-technology vehicles of all types in place by 2020.

The ARB's GHG vehicle emission standards will also affect the future mix of transportation fuels. In August 2005, pursuant to AB 1493 (Pavley, 2002), the Board adopted greenhouse gas emissions standards for new passenger vehicles, beginning with 2009 models (Pavley I). Manufacturers have flexibility in meeting these standards through a combination of reducing tailpipe emissions of carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) and receiving credit for systems demonstrated to mitigate fugitive emissions of hydrofluorocarbons (HFCs) from vehicle air conditioning systems. The emission standards become increasingly more stringent through the 2016 model year. ARB is also committed to further strengthening these standards to obtain an estimated 45 percent greenhouse gas reduction from 2020 model year vehicles (Pavley II). Federal approval of the Pavley I regulation is anticipated, and this analysis considers the impacts of this regulation as part of the baseline fuel forecast case for the LCFS.

The Emission Factors (EMFAC) model is used to calculate emission rates from motor vehicles operating on highways, freeways, and local roads in California. For the AB 32 Scoping Plan, staff used EMFAC to estimate vehicle miles traveled (VMT), fuel use, emissions, and emission reductions for transportation measures identified in the Plan. Gasoline demand in California is expected to decrease slightly between 2010 and 2020.

Another important statute that affects the analysis of the proposed LCFS regulation is the Energy Independence and Security Act of 2007 (EISA). Among other requirements, the EISA enhanced the original federal Renewable Fuel Standard (RFS)—established by the Energy Policy Act of 2005—by requiring the use of 36 billion gallons of renewable fuels annually in 2022, of which only 15 billion gallons can be “conventional biofuel,” principally ethanol derived from corn starch. The remaining 21 billion gallons are to be from sources other than corn starch and are labeled “advanced biofuels.” Sixteen billion gallons must meet a minimum 60 percent reduction in carbon intensity; the remaining five billion gallons must achieve a 50 percent reduction. If EISA is successfully implemented, these federal RFS requirements, referred to as RFS2, will result in changes in U.S. and California transportation fuels.

ARB staff has considered the impact of RFS2 on the proposed LCFS regulation. To that end, staff assessed two alternative cases: one without RFS2 and one with the mandates of RFS2 fully realized. (For a full discussion on how staff addressed RFS2 impacts on the proposed LCFS regulation, see Section F below: “Impact of RFS2 on LCFS.”)

4. Comparison of Fuel Production and Distribution Costs for Gasoline Compliance Scenarios

Staff evaluated costs based on five possible compliance scenarios for gasoline. (See Appendix G for printouts of the gasoline scenario analyses spreadsheets.) The gasoline scenarios differ in the volume of corn-based ethanol, cellulosic ethanol, sugarcane ethanol, and advanced renewable ethanol used; the number of flexible fuel vehicles (FFVs) assumed to be using E85; and the number of advanced vehicles (ZEVs) using electricity or hydrogen.

The least costly means of achieving the LCFS reductions in carbon intensity would be accomplished by using an optimal mix of very-low-CI and lower-cost fuels to the extent that there is sufficient consumer demand for these fuels. Table VIII-8 shows that the least costly compliance, in terms of fuel costs, would rely heavily on electricity and hydrogen. Therefore, maximizing the use of BEVs, PHEVs, and FCVs would result in the lowest compliance cost in terms of fuel. However, in the 2020 timeframe it is not reasonable to expect that there will be sufficient numbers of these vehicles to provide the 10 percent CI reduction proposed for the LCFS; other lower-CI fuels will be needed in significant quantities.

The gasoline scenarios vary ZEV deployment from 560,000 vehicles to two million vehicles. The degree of ZEV deployment will be determined by future ZEV mandates and the market acceptance of ZEVs by consumers, especially when consumers realize the fuel savings provided by PHEVs and BEVs. Since the proposed LCFS regulation does not mandate additional ZEV deployment, staff did not assign the costs of these vehicles to the LCFS regulation. Rather, staff focused on the fuels necessary to accommodate the number and types of California's vehicles on the road, including ZEVs.

For the five gasoline scenarios, staff addressed ZEVs on a "what if" basis—that is, what if there were 560,000 ZEVs on the road, how might this affect compliance with the LCFS? Or what if there were one million or two million ZEVs on the road? Staff then considered the transportation fuel mixtures necessary to achieve compliance with the proposed LCFS regulation for the various scenarios as more electricity or hydrogen is used as a transportation fuel.

a. Common Assumptions

- RFS2 impacts are addressed later in Section F; therefore, they are excluded from the following gasoline scenarios.
- Taxes and biofuel incentives are included in both the petroleum-based fuels and the biofuels and assumed effective throughout 2010-2020. Credits include $0.45 per gallon of ethanol blended and $1.01 per gallon of cellulosic ethanol produced. (See previous subsection i, "Alternative Fuel Tax Incentives," for more information.)
- Based on existing corn ethanol facilities, conventional corn ethanol includes 85 percent from dry mill operation and 15 percent from wet milling process. (All new corn ethanol facilities assumed to be dry-mill facilities.)
- Cost of producing one gallon of "California low-CI corn ethanol" and "federal new renewable ethanol" is the same as dry-mill corn ethanol ($2.83 to $3.08/gge, 2007 dollars) during the compliance period.
- Wood chips, green waste, and corn stover are the common feedstock sources for both cellulosic and advanced renewable ethanol fuels.
- Based on a UC Davis analysis of available biomass in California, green waste, paper, and wood waste could provide 50 percent of feedstock for advanced renewable; wood chips could provide 44 percent; and corn stover and straw would provide the other six percent.
- Ethanol products are E10 and E85. At this time, there are no other ethanol blends, such as E15 or E20, etc.
- There are no new fueling stations for E85, only upgrading a portion of existing gasoline service stations to dispense E85 (one tank and dispenser).
- For any given year:

Total Costs or Savings = Scenario Total Costs - Base Case Total Costs

b. Number of E85 Facilities Required

As discussed previously, all five gasoline scenarios contain a certain number of flexible fuel vehicles (FFVs) penetrating the market that varies depending on the compliance year for a given scenario. Table VIII-10 shows the existing number of public accessible (retail) gasoline dispensing facilities (gasoline stations) in California, based on information in ARB's 2008 report, "Gasoline Dispensing Facility (GDF) Vapor Recovery Hose Population Report"(115).

Table VIII-10
Gasoline Stations in California by Air District

	South Coast	**Bay Area**	**San Joaquin**	**San Diego**	**Other Districts**	**Total**
Number of Gasoline Stations (as of Oct 2008)	5,298	2,581	2,720	1,080	4,493	**16,172**
Statewide %	33%	16%	17%	7%	27%	100%

If E85 is introduced into the market as part of meeting the LCFS and RFS2, staff believes that larger retail stations (greater than two million gallons a year throughput) will invest first in the E85 infrastructure. As the demand for E85 increases, other gasoline stations will invest.

To determine the number of gasoline stations needed to accommodate various volumes of E85, staff started with an annual throughput of E85 of 180,000 gallons per year per gasoline station when E85 first enters the market, increasing the average annual throughput by 20 percent every year until 2020, when the estimated average annual E85 throughput per station would be almost 450,000 gallons. Staff believes that this is a reasonable approach: the initial gasoline stations will not generate significant E85 business until more FFVs are on the road. When the FFVs become more prevalent, the stations investing in E85 will have more business and higher annual throughputs. For the economic analysis, staff expects 100,000 to 350,000 FFVs in 2015 and 1.8 to 3.4 million FFVs in 2020.

c. Scenario 1

(1) Description

This scenario models an increase in ethanol use to 10 percent of gasoline volume by 2010, a steady use of ethanol at that level until 2014, then an increasing use of ethanol in FFVs between 2015 and 2020. Early year compliance is achieved through a gradual decrease in the volume of conventional corn-based ethanol between 2011-2015 as these fuels are replaced with ethanol from low carbon production methods.
From 2015 – 2020, California low-carbon-intensity corn ethanol, federal new renewable ethanol, and advanced renewable fuels replace most conventional corn-based ethanol. (See Chapter VI for complete descriptions of the scenarios.) When the volume of

ethanol (all types) needed to meet lower-CI values cannot be provided by E10 alone, E85 becomes a product available in the marketplace. For Scenario 1, this occurs in 2015. Staff assumes that there will be an adequate number of FFVs on the road to use this E85. From 2015 -2020, the volume of E85 and number of FFVs increase.

The number of advanced vehicles (BEVs, PHEVs, and FCVs) using electricity or hydrogen as a fuel increases to about 560,000 vehicles in 2020. This volume is consistent with the penetration schedule in the 2008 ARB ZEV regulation.

(2) Assumptions

- Annual E85 dispensing per station is based on the ascending throughput discussed earlier (180,000 – 450,000 GPY).
- Number of gasoline stations that will provide E85 is estimated at approximately 4,400 stations by 2020.

(3) Results

Relative to the base case, the total volume of both ethanol and CARBOB remains unchanged until 2015, although the carbon intensity of the ethanol fraction begins to change in 2011. A modest savings occurs in these early years due to the gradual penetration of non-conventional-based corn ethanol (California low-CI, cellulosic, federal new renewable biofuel, and advanced renewable). Staff estimated the production cost of these fuels (except CA low-CI ethanol which has a slightly higher capital cost) to be equivalent to the cost of dry-mill corn ethanol, which is $0.03/gal higher than the ethanol from the wet-mill process that makes up 15 percent of the conventional corn ethanol. E85, and its associated infrastructure costs, arrives on the market in 2015, increasing in volume through 2020. For these years, as ethanol displaces CARBOB in the overall transportation fuel mix, savings are realized due to the lower production cost of ethanol relative to CARBOB. The additional infrastructure costs of E85 marketing contribute to the cost of the greater volumes of ethanol in the market; however, those costs do not overcome the cost differential between producing ethanol and CARBOB. The cost results for Scenario 1 are presented below in Table VIII-11.

The total cost of this scenario and its base case includes the costs of electricity and hydrogen consumption, resulting from 560,000 ZEVS on the road in 2020.

Table VIII-11
Cost Results for Gasoline Fuel Scenario 1

Year	EtOH (billion gallons/yr)		CARBOB (billion gallons/yr)		Additional Non-Liquid Fuel Volume (billion gge/yr)		**Total Cost (Billion Dollars)**	
	B	S1	B	S1	Electricity	Hydrogen	**Baseline**	**S1**
2010	1.45	1.45	13.97	13.97	0.00026	0.00009	$35.90	$35.95
2011	1.44	1.44	13.88	13.88	0.00035	0.00017	$36.33	$36.38
2012	1.43	1.43	13.82	13.86	0.00225	0.00035	$36.85	$36.94
2013	1.43	1.43	13.77	13.77	0.00406	0.00052	$37.60	$37.49
2014	1.42	1.42	13.69	13.69	0.00588	0.00061	$38.48	$38.25
2015	1.41	1.47	13.66	13.62	0.01012	0.00164	$39.18	$38.71
2016	1.40	1.65	13.49	13.34	0.01410	0.00242	$39.49	$38.79
2017	1.39	1.84	13.39	13.09	0.01808	0.00320	$39.79	$38.65
2018	1.37	2.18	13.22	12.67	0.02370	0.00588	$39.89	$38.27
2019	1.35	2.46	13.04	12.30	0.03174	0.00830	$39.95	$37.89
2020	1.33	2.88	12.89	11.84	0.03762	0.01090	$40.07	$37.31

B = Baseline
S1 = Gasoline Scenario 1

d. Scenario 2

(1) Description

This scenario is similar to Scenario 1 except that federal new renewable ethanol is replaced with sugarcane ethanol. Also, there is more total ethanol, which on average has a higher CI than the biofuels used in Scenario 1. The additional ethanol in Scenario 2 requires more E85 and FFVs.

(2) Assumptions

- Annual E85 dispensing per facility is based on the ascending throughput discussed earlier (180,000 – 450,000 GPY).
- Number of gasoline stations that will provide E85 is estimated at approximately 5,000 stations by 2020.

(3) Results

The introduction of ethanol from Brazilian sugarcane makes Scenario 2 more expensive than the base case in the early years. Brazilian sugarcane, although less expensive to produce than conventional corn-based ethanol, is subject to a tariff and an ad valorem tax. Therefore, unlike in Scenario 1, the displacement of federal new renewable corn-based ethanol in 2011 -2020 comes with an additional cost, not a savings. The other major difference between the two scenarios is the need for a much higher FFV penetration from 2018 – 2020, resulting in an increase in E85 and an additional number of gasoline stations (5,000 stations vs. 4,400 stations in Scenario 1). The reduction in

CARBOB reaches approximately 1.2 billion gallons in 2020 due to more E85 in the market. The cost results for Scenario 2 are presented below in Table VIII-12.

The total cost of this scenario and its base case includes the costs of electricity and hydrogen consumption, resulting from 560,000 ZEVS on the road in 2020.

Table VIII-12
Cost Results for Gasoline Fuel Scenario 2

Year	EtOH (billion gallons/yr)		CARBOB (billion gallons/yr)		Additional Non-Liquid Fuel Volume (billion gge/yr)		**Total Cost (Billion Dollars)**	
	B	S2	B	S2	Electricity	Hydrogen	**Baseline**	**S2**
2010	1.45	1.45	13.97	13.97	0.00026	0.00009	$35.90	$35.95
2011	1.44	1.44	13.88	13.88	0.00035	0.00017	$36.33	$36.48
2012	1.43	1.43	13.82	13.86	0.00225	0.00035	$36.85	$37.09
2013	1.43	1.43	13.77	13.77	0.00406	0.00052	$37.60	$37.65
2014	1.42	1.42	13.69	13.69	0.00588	0.00061	$38.48	$38.39
2015	1.41	1.47	13.66	13.62	0.01012	0.00164	$39.18	$38.85
2016	1.40	1.64	13.49	13.34	0.01410	0.00242	$39.49	$38.90
2017	1.39	1.84	13.39	13.09	0.01808	0.00320	$39.79	$38.78
2018	1.37	2.22	13.22	12.63	0.02370	0.00588	$39.89	$38.37
2019	1.35	2.62	13.04	12.19	0.03174	0.00830	$39.95	$37.99
2020	1.33	3.08	12.89	11.71	0.03762	0.01090	$40.07	$37.49

B = Baseline
S2 = Gasoline Scenario 2

e. Scenario 3

(1) Description

This scenario is similar to Scenario 2 except that the number of advanced vehicles (ZEVs) is increased from 560,000 vehicles to 1,000,000 vehicles in 2020. In turn, the number of FFVs using E85 in 2020 and the amount of cellulosic ethanol, advanced renewable ethanol, and sugarcane ethanol are reduced.

(2) Assumptions

- Annual E85 dispensing per facility is based on the ascending throughput discussed earlier (180,000 – 450,000 GPY).
- Number of gasoline stations that will provide E85 is approximately 4,300 stations.
- Electricity and hydrogen to supply the additional ZEVs are taken into account, as well as the necessary infrastructure for dispensing into vehicles. (See discussion below.)

(3) Results

In Scenario 3, Brazilian sugarcane continues to add cost for the years 2011 – 2020. The total amount of CARBOB starts decreasing in 2014, reaching 1.2 billion gallons less in 2020. Conventional corn endures a gradual decrease through 2017, zeroing out in 2018. Similar to Scenario 2, federal new renewable ethanol is absent; however, staff projects the same share of sugarcane with a maximum of 300 million gallons in 2020. Starting in 2014, the cost savings of displacing CARBOB with ethanol overcomes the cost impact of the Brazilian sugarcane, resulting in net savings.

The total cost of this scenario includes the costs of electricity and hydrogen consumption, resulting from one million ZEVS on the road in 2020. (Scenarios 1 and 2 have 560,000 ZEVs) Because of the relatively small amount of energy supplied by electricity and hydrogen (0.52 percent and 0.13 percent, respectively, of the total energy required by the fleet), the economic impact of these fuels and their associated dispensing infrastructure is minimal. The cost results for Scenario 3 are presented below in Table VIII-13.

Table VIII-13
Cost Results for Gasoline Fuel Scenario 3

Year	EtOH (billion gallons/yr)		CARBOB (billion gallons/yr)		Additional Non-Liquid Fuel Volume (billion gge/yr)		**Total Cost (Billion Dollars)**	
	B	S3	B	S3	Electricity	Hydrogen	**Baseline**	**S3**
2010	1.45	1.45	13.97	13.97	0.0003	0.0001	$35.90	$35.95
2011	1.44	1.44	13.88	13.88	0.001	0.0002	$36.33	$36.48
2012	1.43	1.43	13.82	13.86	0.002	0.0003	$36.85	$37.09
2013	1.43	1.43	13.77	13.77	0.004	0.0005	$37.60	$37.63
2014	1.42	1.54	13.69	13.61	0.006	0.0006	$38.48	$38.39
2015	1.41	1.65	13.66	13.32	0.014	0.002	$39.18	$38.38
2016	1.40	1.73	13.49	13.22	0.022	0.004	$39.49	$38.83
2017	1.39	1.87	13.39	12.98	0.030	0.006	$39.79	$38.70
2018	1.37	2.06	13.22	12.65	0.040	0.009	$39.89	$38.36
2019	1.35	2.40	13.04	12.23	0.053	0.012	$39.95	$38.02
2020	1.33	2.80	12.89	11.70	0.070	0.017	$40.07	$37.37

B = Baseline
S3= Gasoline Scenario 3

f. Scenario 4

(1) Description

This scenario is similar to Scenario 3 except the number of advanced vehicles (ZEVs) is increased to 2,000,000 vehicles in 2020.

(2) Assumptions

- Annual E85 dispensing per facility is based on the ascending throughput discussed earlier (180,000 – 310,000 GPY).
- Number of gasoline stations that will provide E85 is approximately 3,800 stations.
- Electricity and hydrogen to supply the additional ZEVs are taken into account, as well as the necessary infrastructure for dispensing into vehicles.

(3) Results

The total cost of this scenario includes the additional costs of electricity and hydrogen consumption, resulting from two million ZEVS on the road in 2020 which lessens the need for liquid fuels. Consequently, there are less FFVs on the road, less E85 on the market, and fewer gasoline stations needed to sell it. Conventional corn ethanol is absent again from 2017 - 2020, replaced by lower CI ethanol. The cost results for Scenario 4 are presented below in Table VIII-14.

Table VIII-14
Cost Results for Gasoline Fuel Scenario 4

Year	EtOH (billion gallons/yr)		CARBOB (billion gallons/yr)		Additional Non-Liquid Fuel Volume (billion gallons/yr)		**Total Cost (Billion Dollars)**	
	B	S4	B	S4	Electricity	Hydrogen	**Baseline**	**S4**
2010	1.45	1.45	13.97	13.97	0.0003	0.0001	$35.90	$35.95
2011	1.44	1.44	13.88	13.88	0.001	0.0002	$36.33	$36.47
2012	1.43	1.43	13.82	13.85	0.004	0.0003	$36.85	$37.10
2013	1.43	1.43	13.77	13.75	0.006	0.0005	$37.60	$37.62
2014	1.42	1.42	13.69	13.65	0.013	0.0008	$38.48	$38.38
2015	1.41	1.41	13.66	13.55	0.029	0.004	$39.18	$38.78
2016	1.40	1.40	13.49	13.31	0.044	0.008	$39.49	$38.81
2017	1.39	1.42	13.39	13.09	0.061	0.013	$39.79	$38.61
2018	1.37	1.66	13.22	12.67	0.079	0.018	$39.89	$38.28
2019	1.35	1.84	13.04	12.20	0.110	0.026	$39.95	$37.76
2020	1.33	2.18	12.89	11.68	0.139	0.034	$40.07	$37.16

B = Baseline
S4 = Gasoline Scenario 4

g. Scenario 5

(1) Description

This scenario is similar to Scenario 3 for the number of ZEVs (1,000,000); however, staff assumes less E85 in 2020 and lower amounts of non-conventional ethanol.

(2) Assumptions

- Annual E85 dispensing per facility is based on 16 percent annual increase.
- Number of gasoline stations that will provide E85 is approximately 4,100 stations.
- Electricity and hydrogen to supply the additional ZEVs are taken into account, as well as the necessary infrastructure for dispensing into vehicles.

(3) Results

The total cost of this scenario includes the costs of electricity and hydrogen consumption, resulting from one million ZEVS on the road in 2020 (Scenarios 1 and 2 have 560,000 ZEVs, while Scenario 3 anticipates one million ZEVs in 2020). Scenario 5 is more expensive than Scenario 3 (even though the total ZEVs are the same) because staff assumes slightly higher volumes of Midwest corn in the early years due to a one-year delay in penetration of cellulosic and advanced ethanol. The economics improve in 2013 because of penetration of cellulosic and advanced renewable ethanol which is less expensive than Midwest and sugarcane ethanol.

Penetration of E85 begins in 2014, a year earlier than with the other scenarios. The higher demand for ethanol is provided by a larger volume of cellulosic and advanced renewable ethanol, which surpasses the sugarcane volume between 2015 – 2020. Also, compared to Scenario 3, there is a larger volume of total transportation fuel. The cost results for Scenario 5 are presented below in Table VIII-15.

Table VIII-15
Cost Results for Gasoline Fuel Scenario 5

Year	EtOH (billion gallons/yr)		CARBOB (billion gallons/yr)		Additional Non-Liquid Fuel Volume (billion gallons/yr)		**Total Cost (Billion Dollars)**	
	B	S5	B	S5	Electricity	Hydrogen	**B**	**S5**
2010	1.45	1.45	13.97	13.97	0.0003	0.0001	$35.90	$35.95
2011	1.44	1.44	13.88	13.88	0.001	0.0002	$36.33	$36.44
2012	1.43	1.43	13.82	13.86	0.002	0.0003	$36.85	$37.11
2013	1.43	1.43	13.77	13.77	0.004	0.0005	$37.60	$37.67
2014	1.42	1.50	13.69	13.64	0.006	0.0006	$38.48	$38.42
2015	1.41	1.62	13.66	13.50	0.014	0.002	$39.18	$38.83
2016	1.40	1.73	13.49	13.22	0.022	0.004	$39.49	$38.83
2017	1.39	1.89	13.39	12.96	0.030	0.006	$39.79	$38.66
2018	1.37	2.08	13.22	12.64	0.040	0.009	$39.89	$38.35
2019	1.35	2.36	13.04	12.23	0.053	0.012	$39.95	$37.99
2020	1.33	2.72	12.89	11.76	0.070	0.017	$40.07	$37.48

B = Baseline
S5 = Gasoline Scenario 5

5. Comparison of Fuel Production and Distribution Costs for Diesel Fuel Scenarios

(See Appendix G for printouts of the diesel scenario analyses spreadsheets.)

a. Common Assumptions

- Biodiesel incentive of $1.00/gal is included and assumed effective throughout 2010-2020. (See previous subsection i, “Alternative Fuel Tax Incentives,” for more information.)
- Conventional renewable biodiesel is derived from soybeans.
- Advanced renewable biodiesel is derived from 85 percent wood chips (F-T) and 15 percent yellow grease (FAHC).
- All biodiesels have about the same energy content of conventional diesel.
- No additional infrastructure for fueling stations are required, assuming biodiesel in the fuels mix remains compatible with the dispensing equipment.
- Sufficient number of CNG fueling stations exists to accommodate increased volumes; however, staff assumed additional dispenser, compressor, and dryer at majority of existing facilities to process additional throughput. In addition, due to the lack of CNG fueling stations along the major freeways, staff projected installing new CNG fueling dispensing systems at existing truck stops. Staff assumed one new station would be built for every five existing stations retrofitted, resulting in 20 percent more stations equipped for CNG fueling.
- For any given year:

Total Costs or Savings = Scenario Total Costs - Base Case Total Costs

b. Scenario 1

(1) Description

The first scenario is based on a diversification of the liquid fuel pool using available lower-carbon-intensity fuels.

(2) Assumptions

- See “Common Assumptions” above.

(3) Results

Since only liquid fuels are involved for this scenario and they all contain the same amount of energy, replacing conventional diesel with its biodiesel counterparts does not affect the total volume for any of the ten years during the compliance period. However, staff projects a much higher volume of advanced renewable biodiesel (CI =15) than conventional biodiesel

(CI =69) in order to achieve the 10 percent reduction in carbon intensity. The cost results for Diesel Fuel Scenario 1 are presented below in Table VIII-16.

Table VIII-16
Cost Results for Diesel Fuel Scenario 1

Year	Conventional Diesel (million gallons/yr)		Biodiesel (million gallons/yr)		CNG	Electricity	**Total Cost (Billion Dollars)**	
	B	S1	B	S1	S1	S1	**Baseline**	**S1**
2010	4,393	4,393	0	0	0	0	$10.89	$10.89
2011	4,484	4,467	0	17	0	0	$11.32	$11.32
2012	4,577	4,542	0	35	0	0	$11.77	$11.76
2013	4,672	4,600	0	72	0	0	$12.30	$12.28
2014	4,768	4,660	0	108	0	0	$12.92	$12.89
2015	4,866	4,676	0	190	0	0	$13.45	$13.39
2016	4,977	4,710	0	267	0	0	$14.04	$13.94
2017	5,091	4,696	0	395	0	0	$14.57	$14.42
2018	5,207	4,688	0	519	0	0	$15.12	$14.91
2019	5,325	4,674	0	651	0	0	$15.69	$15.40
2020	5,445	4,607	0	838	0	0	$16.26	$15.87

B = Baseline
S1 = Diesel Scenario 1

c. Scenario 2

(1) Description

The second scenario includes not only a variety of liquid fuels, but heavy-duty vehicles using compressed natural gas (CNG) vehicles penetrate the fleet.

(2) Assumptions

- Annual CNG throughput of 180,000 gallons per year per station in 2011, increasing the average annual throughput by 10 percent every year until 2020, when the estimated average annual throughput per station would be almost 425,000 gallons.
- In year 2020, upgrading 280 existing CNG stations plus installing CNG fueling at approximately 60 existing truck stops along major freeways.
- CNG has a lower fuel economy than conventional diesel.

(3) Results

Scenario 2 introduces HD CNG vehicles in 2011, with increasing numbers the following years. Compared to the base case, the total volume of transportation fuel will increase by one million gallons in 2013, reaching a maximum of eleven million gallons in 2020.

Since the advanced biodiesel for this scenario comes from F-T diesel from wood chips and FAHC diesel from renewable yellow grease, there are overall savings for this scenario. The cost results for Scenario 2 are presented below in Table VIII-17.

Table VIII-17
Cost Results for Diesel Fuel Scenario 2

Year	Conventional Diesel (million gallons/yr)		Biodiesel (million gallons/yr)		CNG (million gallons of diesel equivalent/yr)	Electricity (million gallons of diesel equivalent/yr)	**Total Cost (Billion Dollars)**	
	B	S2	B	S2	S2	S2	**Baseline**	**S2**
2010	4,393	4,393	0	0	0	0	$10.89	$10.89
2011	4,484	4,465	0	17	2	0	$11.32	$11.32
2012	4,577	4,538	0	35	4	0	$11.77	$11.76
2013	4,672	4,593	0	71	9	0	$12.30	$12.28
2014	4,768	4,648	0	108	13	0	$12.92	$12.88
2015	4,866	4,663	0	183	22	0	$13.45	$13.38
2016	4,977	4,686	0	262	32	0	$14.04	$13.92
2017	5,091	4,661	0	388	47	0	$14.57	$14.38
2018	5,207	4,638	0	511	64	0	$15.12	$14.85
2019	5,325	4,610	0	642	81	0	$15.69	$15.33
2020	5,445	4,530	0	822	104	0	$16.26	$15.78

B = Baseline
S2 = Diesel Scenario 2

d. Scenario 3

(1) Description

The third scenario increases the compliance options by expanding Scenario 2 to include Heavy Duty PHEVs (HD PHEVs).

(2) Assumptions

- CNG has a lower fuel economy than conventional diesel
- In year 2020, upgrading 330 existing CNG stations plus installing CNG fueling at approximately 70 existing truck stops along major freeways.
- Electricity offers a more efficient fuel economy than diesel.

(3) Results

With combined CNG HD and PHEV HD penetration in this scenario, the reduction in total volume of non-liquid fuel becomes greater than the former scenario (from 15 million diesel gallons equivalent (DGE) in 2014 up to 141 million gallons DGE in 2020). Compared to the base case, the total volume of transportation fuel will decrease by one million gallons in 2014, reaching a maximum of five million gallons in 2020.

Similar to the previous two scenarios, advanced renewable biodiesel plays a major role in driving down the costs. Scenario 3 is the least costly of all three cases. The cost results for Scenario 3 are presented below in Table VIII-18.

Table VIII-18
Cost Results for Diesel Fuel Scenario 3

Year	Conventional Diesel (million gallons/yr)		Biodiesel (million gallons/yr)		CNG (million gallons of diesel equivalent/yr)	Electricity (million gallons of diesel equivalent/yr)	**Total Cost (Billion Dollars)**	
	B	S3	B	S3	S3	S3	**Baseline**	**S2**
2010	4,393	4,393	0	0	0	0	$10.89	$10.89
2011	4,484	4,465	0	17	3	0	$11.32	$11.32
2012	4,577	4,536	0	35	5	0	$11.77	$11.76
2013	4,672	4,592	0	68	11	1	$12.30	$12.28
2014	4,768	4,645	0	104	16	1	$12.92	$12.88
2015	4,866	4,657	0	177	28	2	$13.45	$13.37
2016	4,977	4,679	0	254	39	3	$14.04	$13.90
2017	5,091	4,652	0	373	58	5	$14.57	$14.36
2018	5,207	4,627	0	491	79	6	$15.12	$14.83
2019	5,325	4,580	0	635	97	8	$15.69	$15.29
2020	5,445	4,517	0	788	124	10	$16.26	$15.74

B = Baseline
S3= Diesel Scenario 3

D. Cost-Effectiveness

This section discusses the cost-effectiveness of the proposed regulation. AB 32 requires the Board to consider cost effectiveness of each greenhouse gas control measure it adopts. The values must be expressed in dollars per metric ton of CO_2 equivalent. AB 32 does not specify what should be included in the cost calculations nor does it provide criteria to assess if a regulation is or is not cost-effective.

Staff calculated cost-effectiveness values for each compliance scenario developed for the proposed regulation. The values were calculated for each compliance year for 2010 to 2020 and were determined by dividing the net compliance cost for the year by the total metric tons of CO_2 equivalent expected to be reduced for the same year. (See Chapter VII for a discussion of annual CO_2 reductions.) To determine an overall cost effectiveness for each scenario, staff divided the cumulative costs from 2010-2020 by the cumulative emission reductions during that same period. All costs were calculated in 2007 dollars.

As Table VIII-19 shows, the net cost effectiveness, based on the cost of producing or otherwise procuring the needed amounts of lower-CI fuels, for all five gasoline scenarios was negative—the net savings from reduced gasoline production or importation was greater than the net costs of supplying the lower-CI transportation fuels (ethanol, electricity, and hydrogen) that displaced the petroleum-based fuels.

For the five gasoline analyses, the cumulative net cost effectiveness ranged from (\$121) to (\$142)/MT CO_2E reduced, which, for the period of 2010 – 2020, is a cumulative savings of \$8 to \$9 billion. The possible distribution of these savings is discussed later in Section G.

Table VIII-19
Summary of Cost-Effectiveness for the LCFS Regulation for Each Gasoline Fuels Compliance Scenario

Gasoline Scenario 1	Gasoline Scenario 2	Gasoline Scenario 3	Gasoline Scenario 4	Gasoline Scenario 5
(Dollars per Metric Tons of CO_2 Reduced)				
(\$141.58)	(\$120.71)	(\$132.31)	(\$136.86)	(\$130.54)

Similarly, as Table VIII-20 shows, the cumulative net cost effectiveness for all three diesel scenarios was negative—the net savings from reduced diesel production or importation was greater than the net costs of supplying the lower-CI transportation fuels (biodiesel, alternative renewable diesel, CNG, and electricity) that displaced the petroleum-based fuels.

For the three diesel scenarios, the cost effectiveness ranged from (\$49) to (\$67)/MT CO_2E reduced, which, for the period of 2010 – 2020, is a cumulative savings of \$1.3 billion to \$1.7 billion. The possible distribution of these savings is discussed later in Section G.

Table VIII-20
Summary of Cost-Effectiveness for the LCFS Regulation for Each Diesel Fuels Compliance Scenario

Diesel Scenario 1	Diesel Scenario 2	Diesel Scenario 3
(Dollars per Metric Tons of CO_2 Reduced)		
(\$49.17)	(\$61.00)	(\$67.11)

E. Sensitivity Analysis

To conduct the economic analyses of the eight scenarios, staff used the petroleum-based costs of Table VIII-1, the lower-CI fuel costs of Table VIII-8, the appropriate tax credits for the alternative transportation fuels, the costs of the necessary dispensing infrastructure (e.g., E85, hydrogen, CNG), and a real interest rate of eight percent for

10 years. Staff then conducted a sensitivity analysis by varying crude prices, feedstock prices, and interest rates.

1. Crude Oil Prices

With the tax incentives in place for ethanol production and blending, staff dropped the price of crude until the cost of making a gallon of gasoline was the same as making a gge of corn ethanol from corn starting at $3.75/bu (2007 dollars). The cost of corn declines as crude prices decline due to the energy/feedstock and energy/production cost relationships discussed above. The breakeven crude price occurred at $45/bbl. Without the tax incentives, the breakeven price was $110/bbl.

For cellulosic ethanol from wood chips at $30/ton, the breakeven price was $82/bbl without tax incentives. With the $1.01/gal tax credits in place for cellulosic ethanol production, the breakeven price of crude would be less than $10/bbl, so low that the value of the ethanol produced would decline to the point that very little cellulosic ethanol would actually be produced.

For alternative diesel fuels, staff considered the breakeven crude price for biodiesel made from soybeans and Fischer-Tropsch diesel produced from wood chips. Starting out at $0.34/lb for soybean oil, the breakeven crude price was estimated at $30/bbl with incentives and $142/bbl without incentives. For Fischer-Tropsch diesel, starting with $30/ton for wood chips, the breakeven price for crude was less than $10/bbl with incentives, much like with cellulosic ethanol. Without the tax credit, the breakeven price was estimated at $150/bbl.

2. Feedstock Prices

Staff set the crude price at $66/bbl (about the estimated 2010 price) and raised the cost of the ethanol feedstock to find a breakeven feedstock price. For corn ethanol, the breakeven price was $4.15/bu with tax incentives. Without tax incentives the breakeven corn price was $2.90/bu. For cellulosic ethanol from wood chips, the breakeven price was $12/ton without incentives. At this price, there would be insufficient biomass to supply the States biorefineries with feedstock. With incentives, the calculated breakeven point is calculated to be $103/ton, although this hypothetical figure essentially indicates that sufficient biomass would be available to produce cellulosic ethanol at the 18 cellulosic ethanol plants(18).

For alternative diesel fuels, the breakeven price for soybean oil is $0.39/lb with incentives and $0.26/lb without incentives at $66/bbl crude price. For Fischer-Tropsch diesel, the breakeven price for wood chips is $18/ton with incentives, and without incentives F-T diesel made from wood chips is not cost-effective at any crude price.

3. Real Interest Rates

Because of the increased risks of investing in biorefineries, especially cellulosic ethanol plants that have only been built on a pilot-project scale, staff used a real interest rate of eight percent for a 10-year project life. A mature chemical industry might attract capital at a real interest rate of five percent, perhaps over a 20-year period. Staff maintained the 10-year project life and looked at the sensitivity of adjusting the real interest rate downward to five percent and upward to 10 percent. For this sensitivity analysis, staff chose Gasoline Scenario #2 and Diesel Scenario #1, the two scenarios that require more liquid biofuels than the other gasoline and diesel scenarios, respectively. Table VIII-21 shows the impact on cost effectiveness by adjusting real interest rates.

Table VIII-21
Impact of Real Interest Rates on Cost Effectiveness

Real Interest Rate (%)	Gasoline Scenario #2	Diesel Scenario #1
	(Dollars per Metric Tons of CO_2 Reduced)	
5	($139.51)	($71.56)
8	($120.71)	($49.17)
10	($106.06)	($32.75)
13.9	-	~$0
24.1	~$0	-

The breakeven interest rate for diesel is about 13 percent. The Fischer-Tropsch diesel process is capital-intensive; therefore, it would be more affected by interest rates than other processes. (See Table VIII-8.) Conversely, cellulosic ethanol—with a tax credit of $1.01/gal ($1.50/gge)—can endure a much higher interest rate before the cumulative savings from 2010-2020 is driven to zero. Nevertheless, under such a scenario, the LCFS would result in overall costs from 2010-2016 of $1.3 billion and overall savings from 2017-2020 of $1.3 billion.

F. Impacts of RFS2 on LCFS

Staff conducted the LCFS economic analyses considering all costs associated with the use of lower-carbon-intensity alternative transportation fuels, including capital costs, operating costs, and distribution costs. All of the illustrative compliance scenarios showed that when these lower-CI fuels displace petroleum-based fuels in the market—with tax credits in place and crude prices at $66-$88/bbl—there is estimated overall savings to the State.

Even with overall estimated savings, the Energy Independence and Security Act of 2007 (EISA), which established additional federal renewable fuel standards, known as RFS2, will result in significant changes in California’s transportation fuels and require ethanol-related infrastructure to be constructed in the State even without the LCFS. Table VIII-22 below shows the RFS2 requirements explicitly outlined in the EISA.

Table VIII-22
RFS2 Requirements Nationally (Billion Gallons)

Billion Gallons	Renewable Volume Requirements	Advanced Biofuel	Cellulosic Biofuel *	Biomass-Based Diesel	Other Advanced Biofuel	Starch Derived Biofuel (Corn EtOH)
2008	9.00	0.00	0.00	0.00	0.00	9.00
2009	11.10	0.60	0.00	0.50	0.00	10.35
2010	**12.95**	**0.95**	**0.10**	**0.65**	**0.00**	**11.88**
2011	**13.95**	**1.35**	**0.25**	**0.80**	**0.00**	**12.50**
2012	**15.20**	**2.00**	**0.50**	**1.00**	**0.00**	**13.20**
2013	**16.55**	**2.75**	**1.00**	**1.00**	**0.25**	**13.80**
2014	**18.15**	**3.75**	**1.75**	**1.00**	**0.50**	**14.40**
2015	**20.50**	**5.50**	**3.00**	**1.00**	**1.00**	**15.00**
2016	**22.25**	**7.25**	**4.25**	**1.00**	**1.50**	**15.00**
2017	**24.00**	**9.00**	**5.50**	**1.00**	**2.00**	**15.00**
2018	**26.00**	**11.00**	**7.00**	**1.00**	**2.50**	**15.00**
2019	**28.00**	**13.00**	**8.50**	**1.00**	**3.00**	**15.00**
2020	**30.00**	**15.00**	**10.50**	**1.00**	**3.00**	**15.00**
2021	33.00	18.00	13.50	1.00	3.00	15.00
2022	36.00	21.00	16.00	1.00	3.50	15.00

Staff highlighted 2010 -2020, the period of time addressed by the proposed LCFS regulation.

* Cellulosic Biofuel is a subset of Advanced Biofuel. For example, of the 15 billion gallons of Advanced Biofuel required in 2020, 10.5 billion gallons must be Cellulosic Biofuel.

The RFS2 volumetric requirements apply nationwide; where the volumes of renewable fuels are consumed is not mandated. If California were to receive its proportional share of RFS2 fuels, based on historical fuel consumption (11.3 percent of the nation's total), the amount of these fuels in the State is estimated in Table VIII-23 below.

Table VIII-23
California RFS2 Proportional Share (Billion Gallons)

Billion Gallons	Renewable Volume Requirements	Advanced Biofuel	Cellulosic Biofuel	Biomass-Based Diesel	Other Advanced Biofuel	Non-Adv Biofuel (Corn EtOH)
2008	1.02	0.00	0.00	0.00	0.00	1.02
2009	1.25	0.07	0.00	0.06	0.00	1.17
2010	**1.46**	**0.11**	**0.01**	**0.07**	**0.00**	**1.34**
2011	**1.58**	**0.15**	**0.03**	**0.09**	**0.00**	**1.41**
2012	**1.72**	**0.23**	**0.06**	**0.11**	**0.00**	**1.49**
2013	**1.87**	**0.31**	**0.11**	**0.11**	**0.03**	**1.56**
2014	**2.05**	**0.42**	**0.20**	**0.11**	**0.06**	**1.63**
2015	**2.32**	**0.62**	**0.34**	**0.11**	**0.11**	**1.70**
2016	**2.51**	**0.82**	**0.48**	**0.11**	**0.17**	**1.70**
2017	**2.71**	**1.02**	**0.62**	**0.11**	**0.23**	**1.70**
2018	**2.94**	**1.24**	**0.79**	**0.11**	**0.28**	**1.70**
2019	**3.16**	**1.47**	**0.96**	**0.11**	**0.34**	**1.70**
2020	**3.39**	**1.70**	**1.19**	**0.11**	**0.34**	**1.70**
2021	3.73	2.03	1.53	0.11	0.34	1.70
2022	4.07	2.37	1.81	0.11	0.40	1.70

Staff highlighted 2010 -2020, the period of time addressed by the proposed LCFS regulation.

* Cellulosic Biofuel is a subset of Advanced Biofuel. For example, of the 1.7 billion gallons of Advanced Biofuel required in 2020, 1.19 billion gallons must be Cellulosic Biofuel.

Table VIII-23 shows that the total RFS2 ethanol volume for the State, assuming proportional share, is 3.39 billion gallons in 2020. Scenario 2 had the highest amount of ethanol required for compliance at 3.08 billion gallons. Therefore, the total RFS2-mandated volumes of ethanol would satisfy the total volumes required by LCFS. On the other hand, the carbon intensity of the RFS2-mandated ethanol does not meet the requirements of the proposed LCFS; staff estimates that RFS2 will achieve about 30 percent of the GHG emission reductions as the proposed LCFS.

The impact of RFS2 on the proposed LCFS regulation is significant, however, in that the vast majority of the infrastructure costs related to importing, storing, distributing, and dispensing ethanol in California will occur under RFS2, independent of California's adoption of the LCFS. The proposed LCFS regulation would achieve significantly more GHG emissions reduction over RFS2, as discussed in Chapter II, with little additional costs—essentially requiring the biofuels to have a lower carbon intensity than RFS2-compliant fuels. (See discussion in section G.2. below for specific RFS2 impacts on the capital costs of the proposed LCFS.)

The marginal cost of meeting LCFS requirements instead of RFS2 mandates is related to the amount of advanced and cellulosic ethanol used in California's transportation fuels in lieu of corn-based ethanol that would be imported into the State under RFS2. As shown in Table VIII-8, cellulosic ethanol produced from waste products, when the technology is proven on a commercial scale, is estimated to be less costly to produce than corn-based ethanol. Considering the $1.01/gal tax credit for cellulosic ethanol producers, this cost differential is more evident. Therefore, there would be a market incentive to produce more cellulosic ethanol than RFS2 requires.

Should the State's estimated 18 cellulosic ethanol plants be constructed and provide 0.9 billion gallons per year of lower-CI ethanol, then California would have to import about 2.2 billion gallons of lower-CI cellulosic ethanol to meet the requirements of Gasoline Scenario 2. This cellulosic volume should be available nationally, and the LCFS may attract more of it to the State in lieu of Midwest corn ethanol. Furthermore, the cellulosic ethanol required by RFS2 may be lower-CI than the minimum required (a 60 percent reduction from baseline) if sufficient waste cellulosic feedstock can be used.

Staff estimates that, when cellulosic ethanol production is proven on a commercial scale, market forces will result in waste-derived cellulosic ethanol being more cost-effective than corn-based ethanol nationally; the LCFS will attract more volume to the State; and, despite achieving additional GHG emission reductions, the LCFS will not result in incremental costs or savings relative to RFS2.

G. Potential Costs and Savings to California Consumers, Including Businesses

In this section, staff estimates the compliance costs and potential savings for California businesses for the proposed LCFS regulation. The analysis estimates the overall total statewide impact to businesses, the impact to a typical business, and impacts to industry sectors.

1. Possible Distribution of Savings

As summarized in Section D, all of the scenarios resulted in overall savings relative to fuel production, procurement and delivery, as less expensive alternative fuels displaced the more expensive petroleum-based fuels. These savings can be distributed several ways, including:

a. Increased Profits for Lower-CI Fuel Suppliers

The estimated gasoline and diesel production and distribution costs in Table VIII-1 included Energy Commission-estimated "refinery-to-rack" and "rack-to-retail" margins, which contain some profit margin. Therefore, at least some of the estimated net savings will be realized as profits for the lower-CI fuel suppliers.

Given the technical challenges of scaling up pilot-project size biorefineries and the high capital costs of some of the lower-CI-fuel technologies—such as Fischer-Tropsch diesel (at nearly a billion dollars for a 50 MGY plant)—potential investors may require a more attractive rate-of-return before risking capital. Therefore, the lower-CI fuel industry reaping all of the savings as profits is a reasonable scenario.

b. Lower Fuel Prices for Consumers

This estimated savings for the scenarios translates into \$0.02 to \$0.08/gge for the entire California gasoline market, and \$0.03 to \$0.04/DGE for the entire California diesel market. Given that gasoline and diesel retail prices have been volatile over the last couple of years, a savings of one to five cents per gallon of fuel would not seem remarkable for most consumers. Nevertheless, some of the savings could be shared with consumers through lower prices at the pump.

c. Lower Fuel Prices for Specific Consumers

A third option could be a shared savings with consumers for only some lower-CI fuels, such as electricity and hydrogen. An example of this is lower electricity tariffs for recharging electric vehicles during off-peak hours. The power is readily available and provided to the consumer at a reduced rate.

d. Use of Lower-CI Fuels Has Broad Economic Impact on Transportation Fuel Pricing

An increased use of lower-CI fuels may have a broader, more complex impact on the overall transportation fuel market. Examples of these impacts might be:

<u>Lower California gasoline and diesel prices due to lower in-state demand and less pressure on refinery production:</u> The proposed LCFS could reduce demand for petroleum-based transportation fuels in the State, alleviating the pressure on California refineries to produce greater amounts of those fuels. The historic Energy Commission outlooks expected the State refining capacity to increase by about 0.5 percent annually to keep up with increased fuel demands. However, the State's efforts to reduce GHGs from transportation and to diversify the mix of transportation fuels are expected to reduce in-state consumption of petroleum products. Refineries would have less incentive to modify their operations (e.g., debottleneck processes, install additional processing equipment) to produce continually higher amounts of transportation fuel.

With sufficient decline in consumption of petroleum-based transportation fuels, the need for importing fuel blendstocks would decline and price shocks caused by temporary disruptions in refinery capacity would be lessened.

<u>Moderated price increases for crude oil and petroleum products because of greater use of biofuels and other alternative fuels:</u> Lower-CI fuels will compete with petroleum-based products in the market. This competition may have a dampening affect on crude price increases.

<u>Higher overall prices if lower-CI fuels end up costing more than the fuels they replace:</u> Staff understands that the economic analyses of the LCFS is greatly affected by future oil prices and the actual production costs and timing of lower CI alternative fuels. Economic factors, such as tight supplies of lower-CI fuels or a lengthy economic

downturn keeping crude demand down, could result in overall net costs, not savings, of the LCFS. The proposed LCFS allows several years—until 2014 or so—for the introduction of second- and third-generation lower-CI fuels into the market. ARB staff recognizes that RFS2 fuels will have to be available in significant quantities for the proposed LCFS to succeed.

Once adequate quantities of lower-CI fuels are available, disruptions in supply can create temporary price hikes for transportation fuels. The transportation fuel industry in the State should consider potential supply disruptions of liquid biofuels when designing and building the necessary infrastructure to transport and store these fuels.

2. Overall Expenditures and Investments

The total costs that would be associated with the proposed LCFS regulation, absent RFS2, would be the cost of the construction and operation of the biofuel refineries described in Chapter VII, the capital cost of the additional storage capacity of the biofuels, and the cost of the infrastructure necessary to dispense the lower-CI fuels (E85, CNG, hydrogen, and electricity). Capital costs, including installation, are discussed below.

a. Biorefinery Capital Cost

Chapter VII discusses the potential construction of biorefineries in California: eighteen cellulosic ethanol and six corn ethanol plants built by 2020 with a total annual capacity of 1.2 billion gallons, and five F-T diesel and one FAHC diesel plants built by 2020 with a total annual capacity of 300 million gallons. The estimated capital investment for these new businesses is approximately $8.5 billion (five corn ethanol plants are already built). However, because of the requirements of RFS2, staff expects these facilities to be constructed without the proposed LCFS.

According to a UC Davis research paper developed for the Western Governors Association(18), 300 million gallons is the maximum volume of biofuels that can be produced in California. Based on Gasoline Scenario 2, the scenario with the highest overall ethanol demand, and Diesel Scenario 1, the scenario with the highest biodiesel demand, staff estimates that additional biofuels will have to be imported into the State to meet these two illustrative compliance examples. Staff assumes that RFS2 mandates will make these fuels available.

b. Ethanol Storage Tanks

Staff estimates that 35 new ethanol storage tanks with a capacity of one million gallons per tank would have to be built to handle the required volumes of ethanol. The capital investment for installing these new tanks is approximately $1.4 million dollars per storage tank, or $50 million total(88).

c. E85 Dispensers

For E85 dispensing infrastructure, Scenario 2 has the most E85 stations at 5,000. Assuming $172,000 per installation, the total cost would be $860 million.

d. Hydrogen Dispensing

For hydrogen fueling stations, Scenario 4 has the most FCVs. To provide hydrogen for these vehicles, staff estimates that 200 fueling stations would need to be built. At $2.7 million apiece, the total cost would be $540 million.

e. CNG Dispensing

For CNG dispensers, Scenario 3 has the most upgrades to existing CNG stations (330) and new CNG stations (70). Assuming $373,000 for upgrading an existing CNG stations (to increase capacity) and $1 million for a new CNG station at an existing truck stop, the total cost would be nearly $200 million.

f. Electricity

The cost of the electrical infrastructure for PHEVs and BEVs is included in the cost of electricity charged to the customers.

The potential capital cost for the new biorefineries, ethanol storage tanks, and alternative-fuel dispensing are presented in Table VIII-24.

Table VIII-24
Potential Capital Costs

Infrastructure	Capital Cost (million dollars)
25 Biorefineries	8,500[1]
35 Ethanol tanks	50[1]
E85 dispensers	860[1]
CNG dispensers	200[2]
Hydrogen fueling stations	540[2]
Electricity	Not applicable[3]

1 Cost attributable to RFS2
2 Although infrastructure not specifically required to comply with the regulation, it is a possible compliance route
3 Metering cost included in tariff rate

The total potential capital cost of the proposed LCFS regulation—in the absence of the overlapping RFS2 requirements—is estimated at $10 billion over the next decade. However, if the RFS2 mandates are met and California receives its proportional share of RFS2 fuel, virtually all of the capital costs associated with the liquid fuels (ethanol and alternative diesel) would be borne by RFS2, not the LCFS. These would include the biorefineries, the ethanol storage tanks, and the E85 dispensers.

Regarding operating costs, staff assumes that these will include transportation costs of feedstock and product, the routine operational costs of the biorefineries, and maintenance of the new equipment. For the biorefineries, those costs are included in the production-cost estimates in Table VIII-8. For the other infrastructure, including the dispensers, staff assumes maintenance costs of two percent of annual capital recovery, which, at a real interest rate of eight percent for 10 years, is estimated at 14.90 percent of the capital cost, or about $2 million dollars.

3. Costs to Businesses

As discussed above, to accommodate the lower-CI fuels in the market, businesses will have to invest in the necessary infrastructure to produce, distribute, and dispense those fuels.

a. Biorefineries

The costs associated with the expected biorefineries in the State are borne by the investors of those facilities. These investors have risked capital with the expectation of being rewarded with profits commensurate with the risk.

b. Refiners and Fuel Distributors

A refinery or independent blender may have to install an additional storage tank for the increased ethanol volumes. Staff estimated that cost at $1.4 million for a million-gallon (24,000 barrel) tank, including installation. As mentioned previously, RFS2 mandates may require the installation of this tank, regardless of the LCFS.

These same refineries and independent blenders would have to acquire the alternative fuels for blending. These costs are included in the storage, transportation, and distribution costs of the fuels in Table VIII-8. Conversely, these blenders would not receive as much petroleum-based blending stocks, which would offset some of the impact of acquiring the alternative fuels. (Section H below discusses a general overall impact on California businesses.)

Staff assumes that the refineries in the State will continue to operate at capacity. The displaced petroleum-based fuels will come at the expense of imported blendstocks. The importers of these blendstocks, typically oil companies, will be impacted by the proposed LCFS, as these imported blendstocks are used in the California transportation fuel market, which receives a premium price over other markets.

c. Service Station Owners

Since the proposed LCFS regulation does not mandate the installation of E85, CNG, or hydrogen dispensers at any specific facility, facility owners who choose to invest in these fuels will do so with the expectation of recovering the costs and increasing profits.

d. Other Businesses

Electrical utilities, natural gas providers, and hydrogen providers who would wish to opt-in to the LCFS to generate credits would do so voluntarily. Businesses for which transportation fuels are a significant expense (taxis, trucking firms, etc.) should not be impacted by the proposed LCFS, as overall transportation-fuel costs are estimated to decline or be unaffected for the consumer.

If RFS2 or the LCFS induces the utilization of the vegetative and paper fractions of municipal solid waste for biofuel production, compost companies that currently receive green MSW and recycling companies that receive paper would be adversely impacted.

e. Recordkeeping and Reporting Costs

The most obvious additional cost to a business will be recordkeeping and reporting costs. The regulation requires affected parties to submit quarterly progress reports and annual account-balance reports by specified dates using a Web-based, interactive form that ARB staff will establish prior to the implementation of the regulation. The quarterly progress reports are intended to ensure that regulated parties keep track of their ability to comply with the allowable carbon intensity at the end of the annual compliance period. The reports are required to contain a specified set of information and data, such as carbon intensities, fuel volumes sold or dispensed, fuel transfer information, and other information.

The annual account-balance reporting includes the information required for the quarterly reporting, along with additional information relating to the total credits and deficits generated during the year or carried over from the previous year; total credits acquired from another party; total credits transferred to other parties; credits generated and banked in the current year; and any deficits to be carried into the next year.

Records must be kept for three years on the product transfer documents, data and reports submitted to the ARB for this program, records related to each fuel transaction, and records used for compliance or credit calculations.

Staff estimated that it would take one person-year (PY) per affected company to comply with the recordkeeping and reporting requirements. There are 15 refineries in California, four importers of CARBOB/diesel (in 2008), four in-state ethanol producers, and four ethanol importers. Assuming $170,000 per PY, annual reporting and recordkeeping costs would equal $4.6 million for all affected industry.

4. Impact by Industry Sector

The combination of the RFS2 and the proposed LCFS regulation will result in a shift of capital from the petroleum sector to the agricultural, chemical, and electricity sectors. The agricultural sector includes the sources of raw feedstock, such as corn, corn stover, other planted crops, and forest residues. The chemical sector includes the biorefineries, while the electricity sector includes the load-serving entities and other businesses promoting electricity use.

This redistribution of capital among these sectors is essential to the success of the LCFS and RFS2. In fact, RFS2 mandates are part of the Energy Independence and Security Act of 2007, a statute with the explicit goal of reducing petroleum use. Furthermore, in response to AB 1076 (Pavley, 2000), the Energy Commission and ARB prepared and adopted a joint agency report, *Reducing California's Petroleum Dependence*. Thus, the diversification of California's transportation fuels, which requires a shift of capital from the petroleum sector is consistent with well-establish national and State policies.

H. Other Potential Impacts to California Businesses

In this section, staff analyzes the potential impacts of the estimated costs of the proposed regulation on business enterprises. Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administrative regulation, State agencies shall assess the potential for adverse economic impact on California businesses to compete with businesses in other states, the impact on California jobs, and the impact on California business expansion, elimination, or creation.

1. Potential Impact on Employment, Business Creation, Elimination or Expansion

RFS2 mandates will displace traditional petroleum-based fuels with biofuels. The proposed LCFS will reduce the carbon intensity of those biofuels and promote the use of other alternative fuels, such as electricity, hydrogen, and natural gas.

Staff expects the overall impact of the proposed LCFS regulation on California's economy to be neutral to slightly positive, with some fiscal benefits realized locally in the State. The 2007 State Alternative Fuels Plan—required by AB 1007 (Pavley, 2005)—evaluated three illustrative examples of alternative fuel use in California: 1) ethanol and hydrogen fuel cell vehicles (FCVs), 2) biofuels and plug-in hybrid electrical vehicles, and 3) biofuels and hydrogen FCVs. The report stated:

> *The Energy Commission and the ARB used a macroeconomic model to evaluate the statewide impacts of the three examples. The examples all assume significant government incentives to partially offset the costs of alternative vehicles, fuel production, and fueling stations. Overall, considering both public and private sectors, all three examples result in small costs or even net savings (decreased expenditures) in the early years, followed by increased expenditures in later years. The private*

sector experiences savings in nearly all years. These savings are due to the fact that the private sector saves more in avoided petroleum costs than it spends in additional vehicle and infrastructure costs.

An earlier Energy Commission study(116), entitled *Costs and Benefits of a Biomass-to-Ethanol Production Industry in California*, concluded that statewide economic benefits of a California biomass-to-ethanol industry exceed the cost of State support for such an industry. Since that report, RFS2 mandates will require ethanol to enter the transportation fuel market in significant amounts, so the required level of State support for the industry should be less.

While macroeconomic modeling was conducted for these previously analyses, no similar modeling was done for the LCFS regulation. Staff considered using an equilibrium model, such as the Environmental-Dynamic Revenue Analysis Mode (E-DRAM), to conduct a macroeconomic analysis of the proposed regulation. A model such as E-DRAM is most useful when it is used to evaluate the economic impacts of a large-scale policy on the State economy. The model can be informative at the sector level with the understanding that some details that may be important in characterizing how producers will respond to a policy change may not be fully reflected in the model. Because the economic effects of this regulation depend in large part on those responses by the producers, staff determined that this type of macroeconomic analysis would not provide useful additional information.

Generally, the following impacts of the proposed LCFS are assumed:

- Biofuels will displace some percent of petroleum-based transportation fuels.
- The displaced fuels will first be imported blendstocks for transportation fuels, as the State's refineries cannot meet the current demand for these fuels.
- Reducing the volume of transportation fuels that are imported from other states will reduce foreign imports of oil into the U.S.
- State's refineries will continue to operate at capacity during this period. If State demand for fuel declines below this capacity, staff assumes refineries will export fuels at some loss in value since California RFG3 has a premium value.
- The biorefineries expected to be built in the State will provide needed employment, an increased tax base for the State, and value added to the biomass used as feedstock. These benefits will be more important in rural areas of the State that are short on employment but rich in natural resources.
- Displacing imported transportation fuels with biofuels produced in the State keeps more money in the State.

2. Potential Impact on Business Competitiveness

The proposed LCFS regulation will not adversely affect the competitiveness of California businesses. Staff has estimated that the price at the pump will likely be either a small savings of unaffected, so transportation-related businesses will not be harmed. To the extent that California can produce more of its own transportation fuel, lower the amount of money spent on imported oil or petroleum products, and lower dependence on out-of-state biofuels, business competitiveness should be improved overall in the State.

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

1. Impact to Government Revenue

In this section, staff discusses the impact of the LCFS regulation on government revenue. The impacts on each level of government are discussed below and summarized in Table VIII-23. It should be noted that if RFS2 mandates are met and California receives its proportional share of liquid biofuels (as discussed earlier in section F), the revenue impacts from California's share of the biofuels will be attributable to the RFS2 regulation and not the LCFS regulation.

a. Federal

Impacts on federal government revenues are based on federal biofuels subsidies sugarcane ethanol tariffs, and the federal excise taxes on transportation fuels sold in California. These impacts vary among the eight compliance scenarios.

In the gasoline scenarios, the lower energy content of a gallon of ethanol will result in more total volume of transportation fuel sold in California, resulting in greater excise taxes collected. The federal motor fuels excise tax on gasoline is 18.4 cents per gallon sold, regardless of the blend of the gasoline(117). In addition, the 54 cents per gallon and 2.5 percent ad valorem tariffs on imported ethanol (estimated at a total of 60 cents per gallon for sugarcane ethanol) will result in an increase in revenue. Nevertheless, as more biofuels displace traditional transportation fuels, the federal government will spend much more on ethanol subsidies ($0.45/gallon of ethanol blended and $1.01/gallon of cellulosic ethanol produced).

In the diesel scenarios, shifting a portion of traditional diesel fuels to electricity and CNG will result in less federal excise tax collected on transportation fuels sold in California because the tax does not apply to electricity and is less for CNG than for diesel fuels. The federal excise tax on diesel and biodiesel fuels is 24.4 cents per gallon sold(117) and 18.3 cents per gallon equivalent for CNG(114). In addition, the federal government will spend more on subsidies for biodiesel fuels and CNG ($1.00/gallon of biodiesel fuel blended and $0.50/gge of CNG sold).

The regulation would create costs to the Federal government primarily from biofuel tax credits. Staff estimates the potential loss of federal tax revenue to be $1.3 billion to $1.6 billion in 2020—the year of greatest impact—depending on compliance path(s) chosen.

b. State

Impacts on State revenue will be based on State biofuels subsidies, State excise tax and sales tax on transportation fuels sold in California, and the underground storage tank (UST) fee for stored petroleum products. The State biofuel subsidy is in the form of a reduced excise tax for E85. California's excise tax for gasoline and diesel is 18 cents per gallon sold, nine cents per gallon of E85 sold, and seven cents per 100 cubic feet of CNG sold(118). The California state sales tax rate is 6.25 percent(119). The UST fee is 1.4 cents/gallon of fuel stored(120).

As discussed earlier under federal impacts, in the gasoline scenarios, more volume of fuel will be sold in California because of the lower energy content of ethanol. However, some of the volume of traditional gasoline will be displaced by E85, which has a State excise tax of half the value of traditional fuels, resulting in less excise taxes collected. E85 has 25 percent less energy per gallon than E10. To make E85 more affordable for fueling FFVs, staff assumes the retail price of E85 will be 25 percent less than E10. The lower retail price of E85 will result in less State sales tax collected.

In the diesel scenarios, shifting a portion of traditional diesel fuels to electricity and CNG will result in less State excise tax collected on transportation fuels sold in California as well as less UST fees collected. In addition, the retail price of CNG in gallons of diesel equivalent will be less than diesel fuels, resulting in less State sales tax collected.

The regulation would create costs to the State in the form of lost transportation-fuel taxes, including excise taxes and sales tax. There would be no fiscal impact for FY 2009/2010, FY 2010/2011, or FY 2011/2012. Staff estimates the potential loss of annual state tax revenue to be $80 million to $370 million in 2020—the year of greatest impact—depending on compliance path(s) chosen.

c. Local Tax Revenue

The local sales tax rate varies among cities and counties. For the LCFS economic analysis, staff assumed 1.75 percent. As was discussed earlier, more volume of transportation fuel will be sold in California under the gasoline scenarios. However, as E85 accounts for more of the volume sold, its lower retail price will result in less local sales tax collected. Similar to the State impacts, shifting a portion of traditional diesel fuels to electricity and CNG will result in less local sales tax collected on transportation fuels.

The impact of sales tax on transportation fuels from implementing the potential compliance scenarios could either create revenue or result in a revenue loss to local government, depending on the compliance path(s) chosen. The impacts to local sales taxes would be location specific. There would be no fiscal impact for FY 2009/2010, FY 2010/2011, and FY 2011/2012. Staff estimates a potential range of impacts in annual local sales tax revenue of -$51 million to +$2 million from 2013 – 2020.

2. Other Fiscal Effects on Government

The ARB will need resources to implement and enforce the regulation and to contract with third parties to certify particular aspects of a regulated party's claimed fuel pathways. There will be no impact in FY 2009/2010. Staff estimates that three new positions will be needed for FY 2010/2011 and FY 2011/2012—funded at $170,000 per position per year, or $510,000 annually. These annual costs are necessary to enforce the proposed regulation on an ongoing basis. This includes field inspections, reviewing records and reporting, and tracking regulated party compliance with the annual standards. ARB is considering a fee program that would reimburse ARB for costs to implement certain provisions of the proposed regulation related to the review and approval of alternative carbon intensity values for low carbon fuels.

Staff does not anticipate cost to other state agencies to comply with or implement this regulation.

J. Consideration of Alternatives

Staff considered an economic assessment of two alternative approaches to the proposed regulation: 1) implement only the federal RFS2, and 2) implement only a gasoline standard.

1. Implement Only the Federal RFS2

RFS2 achieves only about 30 percent of the GHG reductions projected with the proposed LCFS. (See Chapter X for a discussion of alternatives.) As discussed in Section F above, the marginal cost of meeting LCFS requirements instead of RFS2 mandates is related to the amount of advanced and cellulosic ethanol used in California's transportation fuels in lieu of corn-based ethanol that would be imported into the State under RFS2.

Staff estimates that, when cellulosic ethanol production is proven on a commercial scale, it will be more cost-effective than corn-based ethanol; therefore, under the most conservative assumption, the LCFS will not increase costs relative to RFS2. With significantly more GHG emission reductions, the proposed LCFS is preferred over the RFS-only alternative.

2. Implement Only a Gasoline Standard

Staff analyses of the three illustrative diesel scenarios estimates that, with the tax incentives in place, lower-CI alternative diesel fuels result in an overall savings relative to the base case of strictly petroleum-based fuels. Excluding diesel from the LCFS will forgo 20 percent of the GHG emission reductions from the proposal (see Chapter X), but will also forgo possible overall savings to the State. Therefore, the LCFS is preferred over the gasoline-only alternative.

This Page Left Intentionally Blank

IX. Compliance and Enforcement

The success of the LCFS program depends, in large part, on ARB's ability to account for credits and deficits generated during a compliance period. This will require the reporting and tracking of a regulated party's credit balance during a compliance year, credits bought and sold, credits retained, and other key information required under the regulation. With a few exceptions, the proposal would require reporting to the State to be done electronically to minimize the administrative burden and for efficiency.

To this end, ARB staff is developing a secure on-line LCFS Reporting Tool and Credit Tracking System, a suite of applications that will support the LCFS reporting and tracking requirements. Staff is planning to have both applications available by the end of December 2009. Because these applications are under development, the exact details for these applications remain subject to change. Thus, this Chapter provides a general discussion of these tools, as well as the approach towards overall enforcement of the LCFS.

A. LCFS Reporting Tool

The proposed LCFS mandates that all regulated parties report fuels and other data electronically and on a quarterly and annual basis. The LCFS Report Tool (LRT) will provide a secure, web-based data collection and report-generation application to help regulated parties meet the reporting requirements. Judicious use of these tools can help a regulated party maintain compliance with the regulation and determine if a shortfall is imminent before a violation of the LCFS occurs.

An accompanying step-by-step user guide will be available online. The establishment of the user profile will occur at the point of initial user registration when an account is created and approved. The user account may be the "regulated party" for a fuel(s) or a person responsible for reporting for one or more regulated parties. The linkage between a user and regulated parties will be integrated into the user profile. Along with unique login information, the use of an electronic signature that complies with applicable State law should help deter fraudulent reporting.

1. Identification of Regulated Parties

The identification of the regulated parties will be based upon section 95484 of the LCFS Regulation, "Requirements for Regulated Parties." Depending on the fuel category and whether a transfer of ownership has occurred, the regulated party may be a "producer or importer," a "person", an "entity", "recipient of ownership," or some other party as set forth in the proposal. In cases of transfer of ownership, the LRT will be designed to expect submittal of accompanying documentation of the specific transfer. The different types of regulated parties will incorporated into the LRT.

2. Reporting Requirements

As part of each quarterly and annually report, regulated parties will identify and report fuel carbon intensity values for their fuels, along with the total energy content of each low carbon fuel component replacement for either gasoline or diesel. The general and specific information required for reporting are specified in section 95484(c), which includes the following information from Table 3 of that subsection:

- "Company ID" (linked to specific Regulated Party);
- Reporting period;
- Type of fuel;
- Blended fuel (Y/N);
- If blended, the number of blendstocks;
- Type(s) of blendstock;
- Federal renewable fuel identification (RIN) numbers that are retired for facilities in California (for gasoline and diesel fuel);
- Blendstock type;
- Blendstock feedstock;
- Amount of each blendstock (MJ);
- Feedstock origin;
- Production process;
- Fuel carbon intensity from the Lookup Table;
- Amount of each fuel as gasoline replacement (MJ); and
- Amount of each fuel as diesel fuel replacement (MJ).

This input, along with others specified in the proposal, will be stored in the LRT database. The "unadjusted" (i.e., before adjustment with the Energy Economy Ratio or EER) carbon intensity for the fuel, along with the "compliance" average fuel carbon intensity from Table 1 or 2 in the regulation (whichever applies) will be used in the credit balancing calculation. This calculation will be implemented as part of the credit tracking system described later.

Quarterly progress reporting will begin for calendar year 2010 and continue each year thereafter. This reporting to the LRT is required for all regulated parties, including those that voluntarily opt into the LCFS program solely to generate only credits. The LRT will provide a system-generated online reporting form each quarter for this purpose. Quarterly reports (for the most recently completed quarter) will be required to be in system by May 31st, August 31st, November 30th and February 28th (or 29th) of each year.

The LCFS requires regulated parties to submit an Annual Compliance Report by April 30th (starting in 2012 for calendar year 2011). This reporting is required for each year thereafter. For convenience, staff plans to design the LRT application to remind each regulated party in advance of its annual reporting obligation via email near the end of each reporting period. All report submittals will be date stamped and late reports will be flagged. Those regulated parties that are out of compliance with the quarterly reporting requirements will be notified by the system within 2-3 days of a late submittal.

Only electronically uploaded reports in a specified format will be accepted, rather than hardcopies. As noted, the LRT will require an electronic signature, along with each submitted report, which meets the requirement of Title 2, CCR, section 22000 et al. The LRT will facilitate the uploading of additional scanned information in a PDF file to accompany the online report submittal, if required. This would be in cases where there is a transfer of compliance obligation by written contract and the regulated party must provide the Executive Officer with the “product transfer document” or other written instrument and report the applicable information identified in section 94584(a)(1)(B), (a)(1)(C), (a)(1)(D), (a)(2)(B), (a)(2)(C), (a)(4)(B), (a)(4)(C), (a)(5)(D), or (a)(7)(C), whichever applies.

Output reporting tools will provide regulated parties with access to their data. Our goal is to provide public access to summary reports of LCFS data and related information without disclosing confidential business information or trade secrets.

3. Fuel Carbon Intensity

As noted in Chapter V, the LCFS allows regulated parties to use Method 1, Method 2A or Method 2B, under specified conditions (both 2A and 2B require Executive Officer approval), for determining carbon intensity values for their fuels. These values will reflect the multi-step pathways for producing each fuel. The LRT database will incorporate carbon intensity values from the Lookup Table, which will be accessible online to support LRT users, as well as being accessible to the general public via ARB’s internet site. Those regulated parties using Method 1 will identify the carbon intensity value for a finished fuel directly from the Lookup Table after identifying the fuel and specific feedstock.

As noted in Chapter V, Method 2A will involve customization of the CA-GREET inputs for the fuel pathways in the Lookup Table. Further, Method 2B allows for new fuel pathways to be documented and approved by the Executive Officer. Upon approval by the Executive Officer of a fuel pathway and carbon intensity pursuant to the requirements in Method 2A or 2B, the resulting carbon intensity value will be placed in the Lookup Table and can be selected from the corresponding drop down list.

To account for indirect effects, including land-use changes, regulated parties using Method 2A or 2B would need to petition the Executive Officer to conduct the appropriate modeling analysis as set forth in the LCFS regulation. The results of these analyses will be added to the applicable carbon intensity values in the Lookup Table. The resulting adjusted carbon intensity will be shown in a column in the Lookup Table for use in the credit balancing calculations.

B. Credit Tracking System (CTS)

As an adjunct to the LRT, ARB staff is developing the Credit Tracking System (CTS) as an online application that will enable regulated parties to track their LCFS credit balance and credit trades. The CTS will securely maintain and report credit/deficit status as well as a credit trading history for each regulated party. The user interface will include detailed annotations and online help to facilitate reporting. The System will handle all fuels calculations required to establish the "Credit" or "Deficit" value for each regulated party. This will facilitate the LCFS credit balance determination.

The CTS will compare the overall yearly credits/deficits to the LCFS target value for the compliance period and determine whether the regulated party meets the required credit balance. A positive value will represent "Credits Generated" and a negative value will represent a "Deficit". A zero or positive total credit value will indicate that the regulated party has met its credit balance requirement for that compliance period. A negative value will indicate that the regulated party has not met its credit balance requirement.

The CTS will derive or track the following from input provided by the regulated parties through the companion LCFS Reporting Tool:

- Total credits or deficits generated per reporting quarter;
- Total credits or deficits generated per annual compliance period;
- Carryover credits from the previous annual compliance period used for compliance;
- Credits acquired from another LCFS regulated party during the compliance period;
- A deficit carried over from the previous annual compliance period;
- Credits sold to another LCFS regulated party during the compliance period;
- Credits exported to another program during the compliance period; and
- Credits retired.

The CRT credit/deficit value will be recalculated and updated as new quarterly carbon intensity data are submitted by a regulated party to the CTS through the LCFS Reporting Tool. This will provide up-to-date results for a given annual compliance period. Previously generated compliance values will be saved and maintain as part of the credit tracking history for previous compliance periods.

The system will also maintain a complete history of "transactions" associated with the purchasing, selling, and exporting of credits. This information will be secured and available only to each regulated party that submitted the data, ARB enforcement and program staff, or as otherwise set forth under State law.

C. Description of Enforcement Approaches

Enforcement of the LCFS regulation will generally involve the following activities:

- receiving quarterly and annual reports from the regulated parties;
- reviewing the reports for completeness and accuracy;
- evaluating the data in the reports to determine if the regulated party is in compliance with the requirements of the regulation;
- conducting field investigations and audits of the regulated parties to verify and validate the information submitted in the reports;
- preparing and issuing notices of violation;
- meeting with violators for the purpose of mutual settlement; and
- participating in litigation, if necessary.

It is anticipated that a new database may need to be developed in order to handle the reporting and auditing functions for enforcement purposes.

All these activities are necessary to provide an adequate enforcement presence to maintain a level playing field among the regulated parties, incentivize compliance, and deter noncompliance.

D. Penalties and Other Remedies for Violations of the LCFS

The proposal contains enforcement provisions that authorize the imposition of penalties and other forms of relief for violations of any LCFS provision. The enforcement provisions provide a systematic basis for assessing penalties that are fair, consistent, and effective at maintaining compliance and deterring noncompliance. These provisions are summarized below.

Consistent with Health and Safety Code (H&SC) section 38580 – a State law enacted by AB 32 – the proposed regulation provides that the following remedies are available for a violation of any LCFS provision:

(1) Injunctive relief under H&SC section 41513;
(2) Civil and criminal penalties under H&SC section 42400 et seq.[63]; and
(3) Civil and criminal penalties under H&SC section 43025 et seq.

[63] H&SC Division 26, Part 4, Chapter 4, Article 3, section 42400 et seq. (also referred to as "Part 4").

The proposed regulation additionally provides that any LCFS violation is also subject to all other penalties and remedies permitted under State law.

Under H&SC section 41513, any violation of an ARB regulation may be enjoined by a court in a civil action brought in the name of the people of the State of California. There is no need for the State to show the lack of an inadequate remedy at law, or irreparable damage or loss – showings that are required under some other injunction statutes. Injunctive and other forms of relief may also be available under Business and Professions Code section 17200 et seq. (i.e., for unfair business practices), as well as other applicable State law.

H&SC sections 42400 et seq. provide for criminal, civil, and administrative penalties for violations generally involving nonvehicular sources of air pollutant emissions. It provides a tiered penalty system, with the penalties increasing in severity based on the violator's degree of culpability (i.e., regulated party). Penalties are most severe if the noncompliance results in a specified injury, and under some provisions, if the violator is a corporation.[64] Each day of the violation constitutes a separate offense. As an alternative to civil penalties, ARB may under specified conditions seek administrative penalties as specified in section 42410.[65]

H&SC sections 43025 et seq.[66] set forth penalty provisions specific to ARB's fuel regulations, which are adopted pursuant to ARB's authority to regulate vehicular sources of air pollution. These Part 5 provisions generally parallel the tiered penalty structure for violations set forth in Part 4 (H&SC section 42400 et seq.).[67] Similarly, administrative penalties are authorized as an alternative enforcement mechanism under specified conditions.[68]

Unlike the provisions in Part 4, H&SC section 43029 provides for additional incremental penalties, which are designed to eliminate the economic benefits gained from a regulated party's noncompliance. There are additional penalties for excess emissions based on a per ton multiplier: $9,100 per ton of excess emissions for violations of gasoline requirements, and $5,200 per ton of excess emissions for violations of diesel fuel requirements. These values may be periodically adjusted for inflation.

---

[64] Under the tiered penalty system in Part 4 (H&S section 42400 et seq.), strict liability offenses, negligent offenses, and knowing offenses are all misdemeanors punishable by progressively higher fines and/or jail terms. For example, the fine is up to $1,000 per day for a strict liability offense, $25,000 per day when negligence is involved, and $40,000 per day when the offense is committed knowingly. A violation committed willfully is a public offense with a penalty of up to $125,000 per day. All violations have considerably higher penalties when actual injuries resulted. Corporations are generally subject to higher penalties.

[65] See Cal. Code Reg. title 17 sections 60065.1-60065.45.

[66] H&SC Division 26, Part 5, Chapter 1.5, sections 43025 et seq. (also referred to as "Part 5").

[67] H&SC section 43027 sets maximum penalties for different levels of offenses: $250,000 per day for willful and intentional violations, $50,000 per day when negligence is involved, $35,000 per day for strict liability violations, and $25,000 per day for falsification of records.

[68] See Cal. Code Reg. title 17 sections 60075.1-60075.45.

For penalties under both Part 4 and Part 5, State law provides for potential mitigating factors to be taken into account in assessing the appropriate penalties for a violation, including: the extent of harm caused, the nature and persistence of the violation, the magnitude of excess emissions, the compliance history of the defendant, preventive efforts taken by the defendant, the effort required to comply and accuracy of available test methods, the cooperation of the defendant during investigations, and business size.[69]

[69] See H&SC sections 42403 and 43031.

This Page Left Intentionally Blank

X. Analysis of Alternatives

In this Chapter, we provide an analysis of the alternatives to the proposed regulation. The Chapter is divided into two sections. The first section addresses alternative approaches to the proposed regulation. The second section addresses various specific alternatives to specific provisions of the regulation. A detailed discussion of each alternative considered follows in the subsections below.

A. Alternative Approaches to the Regulation

The staff analyzed four different approaches to the regulation; these are summarized below:

- Only implement the federal renewable fuels program;
- Implement a gasoline standard only;
- Delay LCFS Pending Possible National Regulation; and
- Delay LCFS Pending Development of Regional GHG Programs.

ARB staff evaluated these four potential alternative approaches to the regulation and found that none was more effective in carrying out the purpose of the proposed regulation, or would be as effective and less burdensome than the proposed regulation. The following sections discuss each alternative.

1. Implement Only the Federal RFS2

The U.S EPA has adopted its Renewable Fuel Standard (RFS2) regulation—title 40, Code of Federal Regulations (CFR), part 80, section 1100 et seq.— that mandates the blending of specific volumes of renewable fuels into gasoline and diesel sold in the U.S. each year. As defined, “renewable fuels” under the RFS superficially resembles the list of liquid transportation fuels subject to the LCFS. However, there are a number of reasons why the RFS2 is not comparable to the LCFS.

Congress adopted a renewable fuels standard in 2005 and strengthened it in December 2007 as part of the Energy Independence and Security Act (EISA). The RFS2 requires that 36 billion gallons of biofuels be sold annually by 2022, of which 21 billion gallons must be “advanced” biofuels and the other 15 billion gallons can be corn ethanol. The advanced biofuels are required to achieve at least 50 percent reduction from baseline lifecycle GHG emissions, with a subcategory required to meet a 60 percent reduction target. These reduction targets are based on lifecycle emissions, including emissions from land use changes. Additional information on the RFS2 is presented in Chapter II.

Although the RFS2 is a step in the right direction, the RFS2 volumetric mandate alone will not achieve the objectives of the LCFS. The RFS2 targets only biofuels and not other alternatives; therefore, the potential value of electricity, hydrogen, and natural gas are not considered in an overall program to reduce the carbon intensity of transportation fuels. In addition, the targets of 50 percent and 60 percent GHG reductions only establish the minimum requirements for biofuels. It forces biofuels into a small number of fixed categories and thereby stifles innovation. Finally, it exempts existing and planned corn ethanol production plants from the GHG requirements, thus providing no incentive for reducing the carbon intensity from these fuels.

By contrast, the LCFS regulates all transportation fuels, including biofuels and non-biofuels, with a few narrow and specific exceptions. Thus, non-biofuels, such as compressed natural gas, electricity, and hydrogen, play important roles in the LCFS program. In addition, the LCFS encourages much greater innovation than the federal program by providing important incentives to continuously improve the carbon intensity of biofuels and to deploy other fuels with very low carbon intensities.

If California were to rely solely on the RFS2 (i.e., the "No LCFS" alternative), the State would not achieve the GHG emission reductions called for in AB 32 Scoping Plan and Executive Order S-01-07. The RFS2, by itself, achieves only approximately 30 percent of the GHG reductions projected under the LCFS program. Additional details on this analysis are presented in Chapter VI. Therefore, this alternative was deemed to be not as effective as the proposed action.

Furthermore, as discussed in Chapter VIII, the marginal cost of meeting LCFS requirements instead of RFS2 mandates is related to the amount of advanced and cellulosic ethanol used in California's transportation fuels in lieu of corn-based ethanol that would be imported into the State under RFS2.

Staff estimates that, when cellulosic ethanol production is proven on a commercial scale, it will be more cost-effective than corn-based ethanol; therefore, under the most conservative assumption, the LCFS will not increase costs relative to RFS2. With significantly more GHG emission reductions, the proposed LCFS is preferred over the RFS-only alternative.

2. Implement a Gasoline Standard Only

The LCFS includes two separate standards for gasoline and the alternative fuels that can replace it, and for diesel fuel and its replacements. A gasoline standard only approach has been advocated by various stakeholders to allow for a simpler implementation of the regulation in the early years. ARB staff does not support this approach as discussed below.

Staff believes that a comprehensive approach from the beginning will allow for the development of a more robust credit market and will provide greater certainty on future expectations. Fuel producers will need to consider overall approaches to providing low carbon transportation fuels. Given the fact that the compliance requirements are substantially less in the early years should provide fuel producers adequate time to develop appropriate compliance options. In addition, because diesel accounts for approximately 20 percent of the total liquid transportation pool of California, failure to include diesel will result in a loss of approximately 20 percent of the LCFS benefits. Therefore, this alternative would not meet the requirements of AB 32 and was deemed to be not as effective as the proposed action.

From an economic perspective, staff analyses of the three illustrative diesel scenarios estimate that, with the tax incentives in place, lower-CI alternative diesel fuels result in an overall savings relative to the base case of strictly petroleum-based fuels. (See Chapter VIII.) Excluding diesel from the LCFS will not only forgo 20 percent of the GHG emission reductions from the proposal, but will also forgo possible overall savings to the State. Therefore, the LCFS is preferred over the gasoline-only alternative.

3. Delay LCFS Pending Possible National Regulation

In taking positive steps toward reducing GHG emissions, ARB staff believes that California should not simply defer to the federal government. Deferring to the federal government would conflict with the requirements of AB 32 and Executive Order S-01-07. As such, ARB is without authority to simply defer to the federal government. Moreover, the implementation of successful state-level programs can hasten the development of similar programs by other states, and, ultimately, by the federal government. Similarly, a single successful national program based on California's efforts can stimulate the development of related programs in other nations. In this respect, California seeks to implement an LCFS that will accelerate the adoption of similar measures nationally, and, possibly, internationally.

Even if ARB were to defer to the federal government, doing so would not ensure that effective action at the federal level would be taken in the near future to meet the requirements of AB 32. The U.S. EPA has not specified a timeframe by which it would develop a national LCFS-type regulation. Therefore, deferring to the federal government's efforts to develop a national LCFS program would be unacceptably
open-ended. Based on the above reasons, staff deemed this alternative as infeasible and not as effective as the proposed action.

4. Delay LCFS Pending Development of Regional GHG Programs

One potential regulatory alternative would be to delay the LCFS regulation pending development of regional GHG programs, like the one under development by the Western Climate Initiative (WCI). In the Western Climate

Initiative Design Recommendations document, the Partners recommended the WCI include direct emissions from gasoline and diesel combusted as transportation fuel. They also recommended that direct CO_2 emissions from the combustion of pure biofuels be excluded from the cap-and-trade program.

ARB staff believes it is critical to include full fuel-lifecycle GHG emissions and to address both fossil fuels and biofuels. Therefore, California is moving forward with the development of the LCFS. We recognize that combined state, national, and international efforts are necessary to solve the global warming crisis. We will continue to coordinate our work with the states and Canadian provinces in the Western Climate Initiative. We appreciate their efforts to reduce greenhouse gases, and we will work with the WCI partners in their future efforts to assess whether and how to include upstream emissions associated with bio and fossil fuels prior to the start of the cap and trade program.

At this time, ARB staff understands that the WCI is awaiting California's development of the LCFS regulation before the WCI establishes its regional regulation. Because of this, delaying the LCFS development while the WCI's efforts are pending would make little sense. Therefore, staff deemed this alternative as infeasible.

B. Specific Proposed Modifications to the Regulation

1. Exclude Indirect Land Use Effects

Carbon intensities are calculated under the LCFS on a full fuel lifecycle basis. This means that the carbon intensity value assigned to each fuel reflects the GHG emissions associated with that fuel's production, transport, storage, and use. In addition to these direct GHG emissions, some fuels create emissions due to indirect land use change effects. An indirect land-use change impact is initially triggered when an increase in the demand for a crop-based biofuel begins to drive up prices for the necessary feedstock crop. This price increase causes farmers to devote a larger proportion of their cultivated acreage to that feedstock crop. Supplies of the displaced food and feed commodities subsequently decline, leading to higher prices for those commodities.

The lowest-cost way for many farmers to take advantage of these higher commodity prices is to bring non-agricultural lands into production. These land use conversions release the carbon sequestered in soils and vegetation. The resulting carbon emissions constitute the "indirect" land use change impact of increased biofuel production.

Efforts to model indirect land use impacts indicate that the full lifecycle carbon intensities of some biofuels may be similar to or even higher than the carbon intensities of conventional petroleum-based fuels. ARB staff has been and will continue to work with modelers at the University of California and Purdue

University to derive indirect land use change estimates that are empirically based, defensible, and fully open to public scrutiny and comment.

Based on the work done to date, crop-based biofuels contribute to some indirect land use impacts. However, the magnitude of this impact has been questioned by renewable fuel advocates. Land use change is driven by multiple factors. Because the tools for estimating land use change are few and relatively new, biofuel producers argue that land use change impacts should be excluded from carbon intensity values pending the development of better estimation techniques. Based on its work with university land use change researchers, however, ARB staff has concluded that the land use impacts of crop-based biofuels are significant and must be included in LCFS fuel carbon intensities. To exclude them would allow fuels with carbon intensities that are similar to gasoline and diesel fuel to function as low-carbon fuels under the LCFS. This would delay the development of truly low-carbon fuels and jeopardize the achievement of a 10 percent reduction in fuel carbon intensity by 2020.

Additonal information on excluding indirect land use from the proposed regulation is presented in Chapter VI.

Based on the reasons discussed above, ARB staff deemed this suggestion as infeasible.

2. Include Light Duty Diesel Vehicles

This suggested modification would treat diesel-fueled, light-duty vehicles (diesel LDVs) as being alternative vehicles to gasoline LDVs and give them credit accordingly for reduced carbon intensity as compared to gasoline.

Staff agrees that light-duty vehicles are more energy efficient than gasoline vehicles. Staff estimates that there is about a 20 percent improvement in the adjusted carbon intensity of light-duty diesel vehicles using conventional diesel fuel compared to gasoline vehicles. However, the focus of the LCFS is encouraging and promoting improvements in the carbon intensity of conventional fuels. The use of conventional diesel fuel would not achieve the objective of encouraging low carbon fuels. Furthermore, unlike electric vehicles or fuel cell vehicles, allowing light-duty diesel vehicles in the LCFS does not provide any significant long term benefits of promoting significantly lower carbon fuels and more energy efficient vehicles.

In addition, the introduction of these vehicles would already be credited under the vehicle GHG regulations[70] adopted pursuant to AB 1493 (Pavley, Stats. 2002, ch. 200). Thus, assigning LCFS credits for diesel LDVs would amount to double crediting. This would result in a substantial loss in GHG reductions due to the LCFS. Therefore, staff deemed this suggested modification as infeasible.

[70] 13 CCR §§1900, 1961, and 1961.1.

Additional information on the impact of including light-duty diesel vehicles is presented in Chapter VI.

3. Develop Oil Sands/Oil Shale-Specific Pathway

The methods used to extract, refine, and transport crude from oil sands, oil shale and other high carbon-intensity crude sources can result in a relatively high carbon-intensity rating for that feedstock. Staff is developing a pathway or pathways for petroleum fuels refined from high carbon-intensity crude oil, including crude oil from oil sands. The carbon intensity for those pathways will likely be higher for most pathways than the carbon intensity of fuels refined from conventional crude oils. However, the proposed regulation generally requires accounting for these higher intensity crude oils that are not currently used in California and sets forth alternatives, provided the regulated party establishes that the higher GHG emissions from those crude oils are substantially mitigated through carbon capture and sequestration or similarly innovative technologies.

4. Electricity Accounting Methods for Electric Vehicles and Plug-In Hybrid Electric Vehicles

ARB staff proposes to allow both electric vehicles and plug-in hybrid vehicles to generate LCFS credits, provided the electricity used to charge the vehicle is directly metered and reported by the regulated party. Under a statewide Advanced Metering Initiative, utilities are replacing old meters with new, more sophisticated digital meters from 2009 through 2011-13 (depending upon the individual utility.)

Stakeholders recommended that the requirement of direct metering apply only when customers receive advanced meters with sub-metering capability, or 2015 (whichever is earlier). They also suggested that, until the direct metering requirement is applied under their recommended schedule, the utilities be allowed to use an estimation technique to generate credits, possibly with discounting factors to account for uncertainty. Stakeholders noted that, under the “cost of service” regulation by the California Public Utilities Commissions and the governing boards of municipal utilities, the cost of the second meter for transportation purposes is borne solely by the electric transportation customer. Furthermore, they state that it will take 2-3 years for the development, testing, and verification of sub-metering capability to be incorporated into utility advanced meters and systems (2011-2012 timeframe).

Under the proposed regulation, ARB staff has determined that a requirement for direct metering is the most accurate method for determining electric vehicle or PHEV charging. However, staff is further investigating the technical challenges of sub-metering electric vehicle charging and the timeframe for the technology roll-out. Staff will propose amendments to the proposed regulation if the analysis demonstrates an alternative method should be used in the early years of the program.

5. Alternative Marine Power

Electric alternative marine power, also known as cold ironing or port electrification, provides shore-side electrical power to a ship at berth while its main and auxiliary engines are turned off. Alternative marine power replaces the use of petroleum fuels when a ship is at dock. Stakeholders have suggested that the use of alternative marine power should generate LCFS credits. However, subjecting the production of bunker and marine distillate fuels (i.e., those fuels used in ocean-going vessels) to the LCFS requirements would present jurisdictional challenges that are beyond the scope of the LCFS rulemaking. Such fuels are produced in countries outside the U.S., and subjecting the production of those foreign-made fuels to the average carbon-intensity requirements of the LCFS would be problematic, at best. Therefore, the proposed regulation does not consider fuels used in marine vessels (other than commercial harborcraft) as transportation fuels that would be eligible for generating LCFS credits.

6. Truck Stop Electrification

Truck stop electrification provides electrical power from the grid for truckers to operate the trucks' heater, air-conditioner and electrical appliances while at the truck stop, rather than running the truck engine to generate electricity. Electricity used by trucks at truck stops in California is considered a transportation fuel and could generate LCFS credits, provided the metering, reporting and other requirements of the regulation are satisfied.

7. Electric Transport Refrigeration Units

Transport refrigeration units (TRU) are refrigeration systems typically powered by diesel internal combustion engines designed to refrigerate or heat perishable products that are transported in various containers, including semi-trailers, truck vans, shipping containers, and rail cars. Although TRU engines are relatively small, ranging from 9 to 36 horsepower, significant numbers of these engines congregate at distribution centers, truck stops, and other facilities, resulting in the potential for health risks to those that live and work nearby. The ARB adopted an Airborne Toxic Control Measure for transport refrigeration units and TRU generator sets, which requires owners and operators of such equipment to meet stringent PM emissions levels; to have them retrofitted with a PM control device; or to use an alternative technology (including the use of electric standby or other approved technology).

The proposed LCFS regulation does not provide for the generation of LCFS credits from the use of electric transport refrigeration units. The incremental benefits of using electric transport refrigeration units beyond what is required or eligible for early credits in the transport refrigeration regulation are not expected to be large, and the benefits would be difficult to verify. Therefore, staff is proposing not to allow LCFS credits for electric transport refrigeration units.

8. Electric Forklifts

Forklifts are powered industrial trucks used to lift and transport materials, typically in manufacturing and warehousing operations. In a typical warehouse setting most forklifts used have load capacities between one to five tons. Larger machines, up to 50 tons lift capacity are used for lifting heavier loads. Forklifts are generally electric-, propane-, or diesel-powered, although some gasoline and natural gas models are available. Electric forklifts are common in food warehouses and indoor applications where CO2 emissions from internal combustion engine forklifts could cause food spoilage or worker safety issues.

In 2006, ARB approved a rule to reduce emissions from propane, gasoline, and natural gas forklifts and other large spark ignited equipment. The rule has two elements. The first requires forklift engine manufacturers to meet more stringent emission limits for new forklifts sold in California. The second element requires operators of existing forklifts to reduce emissions by retrofit or replacement of the engines or equipment with cleaner models, which could include electric forklifts.

a. Existing Forklifts and Similar Equipment

Stakeholders have proposed that existing electric forklifts and other off-road electric transportation equipment be included in the 2010 baseline GHG level for diesel and that all electric forklifts both existing and new be metered and allowed to generate LCFS credits. Under this suggested modification, the stakeholders argue that the correction for existing equipment would already be included in the baseline standard. However, ARB staff is concerned that this approach allows credits for new equipment that would have been electric anyway, in the absence of the low carbon fuel standard. Therefore, ARB staff proposes not to include existing electric equipment in the baseline and not to subsequently allow all electric equipment to generate LCFS credits.

b. New Categories of Use

The above concerns notwithstanding, new electric forklifts that displace internal combustion engines can provide significant emissions benefits. Hence, ARB staff proposes that electric forklifts in new applications or categories of use be eligible to generate LCFS credits. Electric forklifts required under regulation or used in common practice would not be eligible. A mechanism to allow generation of credits from new categories of electric forklifts needs to be developed before LCFS credits could be generated.

9. Establish a Cap on Early Year Credits

A concern has been raised regarding the possibility of generating substantial excess credits by some alternative fuels in the early years of the LCFS program, which in turn might stifle the development of low carbon-intensity fuels in the future. Staff has evaluated this concern and has determined that it is unlikely to occur. To illustrate, our analysis of sugarcane ethanol (the most likely scenario for generating excess credits) shows that, although this fuel is expected to have low GHG emissions in some respects, it will have large, offsetting land-use effects. Thus, the carbon intensity for this fuel will be relatively high, thereby making it unlikely that excess credits in the early years will be generated.

However, staff will continue to monitor the amount of credits generated and banked and will consider appropriate action based on the information available.

10. Establish Different Energy Economy Ratios for Vehicles

Some stakeholders have advocated for different Energy Economy Ratios (EERs) different from those used by staff in the Staff Report be used for vehicles with emerging, alternative fuel technologies. Staff has determined that this suggestion cannot be implemented at this time due to the lack of data on such emerging technologies. Staff's current analysis incorporates the best available data that are representative of alternative fueled vehicles that are commercially available today or in the very near future.

With that said, the best available data on EERs are nevertheless based on limited fuel economy data available for emerging alternative technology vehicles. For example, in the case of advanced technology or emerging vehicles such as battery electric vehicles (BEV), plug-in hybrid electric vehicles (PHEV), fuel cell vehicles (FEV), and heavy-duty compressed natural gas (CNG) or liquefied natural gas (LNG) vehicles, the data are limited to one or two vehicles per category. Therefore, the proposed regulation specifies EER values for use until such time that there are more updated data available. As there will only be a limited number of these advanced vehicles available in the first few years of the LCFS, the amount of credits generated is not likely to be significantly affected. Staff is committed to review and update these and other EERs as better data become available.

11. Use of External GHG credits

The proposed regulation disallows the use of GHG credits that are generated outside the LCFS program. This is to ensure that improvements in the LCFS fuel pool occur. However, staff will continue to evaluate the feasibility and effectiveness of allowing credits generated from marine and aviation transportation areas, which are not currently included in the LCFS fuel pool, to be used in the LCFS program. ARB staff will provide an update on the potential use of greenhouse gas credits from lower carbon marine and aviation fuels to be used in the LCFS program as part of the periodic reviews.

References:

1. ARB and CEC (2007). State Alternative Fuels Plan. California Air Resources Board.
2. Arnold Schwarzenegger (2007) S-01-07
3. Alexander E Farrell, Daniel Sperling, and et al. (2007). A Low-Carbon Fuel Standard for California Part 1: Technical Analysis
4. Alexander E Farrell, Daniel Sperling, and et al. (2007). A Low-Carbon Fuel Standard for California Part 2: Policy Analysis.
5. Arnold Schwarzenegger (2006) S-06-06
6. ARB (2008). Climate Change Scoping Plan. O.o.C. Change. California Air Resources Board.
7. Arnold Schwarzenegger (1999) D-5-99
8. (2007). Energy Independence and Security Act of 2007.
9. US EPA (2008). Renewable Fuels Standard for 2008. US Environmental Protection Agency.
10. US EPA (2009). Renewable Fuels Standard for 2009. US Environmental Protection Agency.
11. California Office of the Governer. (2007). "Governor Schwarzenegger Signs Agreement with British Columbia Premier Campbell to Fight Global Warming." Retrieved, from http://gov.ca.gov/index.php?/press-release/6521/.
12. EurActiv.com. (2008). "The review of the EU's Fuel Quality Directive." Retrieved, from http://www.euractiv.com/en/transport/review-eu-fuel-quality-directive/article-167990.
13. IHS. (2008). "EC's Fuel Quality Directive to be Amended." Retrieved, from http://energy.ihs.com/News/petrochemicals/2008/eu-en-fuel-quality-12-08.htm.
14. California Board of Equalization. (2008). "Fuel tax rates." Retrieved, from http://www.boe.ca.gov/sptaxprog/spftrpts.htm.
15. EIA. (2007). "U.S. Product Supplied for Crude Oil and Petroleum Products." Retrieved, from http://tonto.eia.doe.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm.
16. CEC. (2009). "California's Oil Refineries " Retrieved, from http://energyalmanac.ca.gov/petroleum/refineries.html.
17. ARB (2007). Emfac 2007. Air Resources Board.
18. Antares Group (2008). Strategic Assessment of Bioenergy Development in the West.
19. US EPA (2007). Regulatory Impact Analysis: Renewable Fuel Standard Program. O.o.T.a.A. Quality. 116-170.
20. RFA (2009). Renewable Fuels Association Biorefineries Locations. Renewable Fuels Association.
21. Renewable Fuels Association. (2007). "Renewable Fuels Association Ethanol Industry Statistics." Retrieved, from http://www.ethanolrfa.org/industry/statistics/#E.

22. (2007). Congressional Research Service Report for Congress; Agriculture Based Renewable Energy Production.
23. (2008). Attachment E for Landfill Methane as a Biomass Renewable Energy Source.
24. CEC (2005). Biomass Resource Assessment in California. California Energy Commission.
25. ARB (1998). Noncombustion Landfill Gas Control Technologies. California Air Resources Board.
26. GTI and Prometheus Energy Company (2007). GTI and Prometheus Energy Company Grant Application Package. California Air Resources Board.
27. Oregon. (2007). "Biomass Energy Homepage." Retrieved, from http://www.oregon.gov/ENERGY/RENEW/Biomass/biogas.shtml#Anaerobic_Digestion.
28. CEC. (2008). "Biomass - Anaerobic Digestion." Retrieved, from www.energy.ca.gov/research/renewable/biomass/anaerobic_digestion/index.html.
29. Hilarides (2007). Hilarides Dairy Grant Application Package. California Air Resources Board.
30. NGSA (2004). Overview of Natural Gas. Natural Gas Supply Association.
31. Michelle Fost (2007). Introduction to LNG. UT Austin.
32. CEC (2009). Significant Events in the History of LNG. California Energy Commission.
33. EIA. (2009). "Natural Gas Plant Processing." Retrieved, from http://tonto.eia.doe.gov/dnav/ng/ng_prod_pp_dcu_nus_a.htm.
34. EIA. (2009). "U.S. Natural Gas Imports by Country " Retrieved, from http://tonto.eia.doe.gov/dnav/ng/ng_move_impc_s1_a.htm.
35. CLNG. (2008). "Bringing LNG to the United States." Retrieved, from http://www.lngfacts.org/LNG-Today/Bringing-LNG.asp.
36. Fritz R. Kalhammer, Bruce M Kopf, and et al. (2007). Report of the ARB Independent Expert Panel. Air Resources Board.
37. Michael Kintner-Meyer, Kevin Schneider, and Robert Pratt (2007). Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids Part 1: Technical Analysis. Pacific Northwest National Laboratory.
38. Lucy Sanna (2005). "Driving the Solution: The Plug-In Hybrid Vehicle." EPRI Journal.
39. Rolf Schreiber. (2008). "Vehicle to grid (V2G) overview." Retrieved, from http://rechargeit.blogspot.com/2008/09/vehicle-to-grid-v2g-overview.html.
40. NRC (2008). Traditions to Alternative Transportation Technologies: A Focus on Hydrogen. National Academy of Sciences.
41. Sasol Chevron (2008). The Greenhouse Gas Impact of Gas to Liquids (GTL), An Industry Perspective. Chevron.
42. Anders S Carlsson, et al. (2007). Micro- and Macro-Algae: Utility for Industrial Applications. Outputs from the EPOBIO Project.

43. DOE. (2009). "Alternative and Advanced Fuels, Butanol as an Alternative Fuel." Retrieved, from http://www.afdc.energy.gov/afdc/fuels/emerging_biobutanol_what_is.html.
44. Eric J Steen and et al. (2008). "Metabolic engineering of Saccharomyces cerevisiae for the production of n-butanol." Microbial Cell Factories 7(36).
45. David; Yang Ramey, Shang-Tian (2004). Work performed under contract number: DE-F-G02-00ER86106 for U.S. Department of Energy. US Department of Energy.
46. Argonne (2008). The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. Argonne National Laboratory.
47. ARB (2008). California-GREET Model version 1.8b. Air Resources Board. http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.
48. S. Solomon and et al. (2007). Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Intergovernmental Panel on Climate Change.
49. Aspentech ASPEN. Aspentech.
50. T. Searchinger, et al. (2008). "Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land Use Change." Science 319: 1238-1240.
51. L. B. Guo and R. M. Gifford (2002). "Soil Carbon Stocks and Land Use Change : A Meta Analysis." Global Change Biology 8: 345-360.
52. D. Murty, et al. (2002). "Does Conversion of Forest to Agricultural Land Change Soil Carbon and Nitrogen ? A Review of the Literature." Global Change Biology 8: 105-123.
53. Michael O'Hare and et al. (2009). Proper accounting for time increases crop-based biofuels' GHG deficit versus petroleum. UC Berkeley.
54. R. Keeney and T. W. Hertel (2008). Indirect Land Use Impacts of US Biofuels Policies: The Importance of Acreage, Yield and Bilateral Trade Responses. GTAP Working Paper 52. Purdue University.
55. NASS (2009). Agricultural Prices. US Department of Agriculture.
56. Brazilian Ministry of Agriculture (2008). Livestock and Supply. Brazilian Ministry of Agriculture.
57. Wallace E. Tyner, Farzad Taheripour, and Yu Han (2009). Preliminary Analysis of Land Use Impacts of Cellulosic Biofuels. Purdue University.
58. Matt Liebman and Andrew H. Heggenstaller (2008). Stoking the Dragon: Can We Produce Feedstocks Sustainably? , Iowa State University.
59. BRDI (2008). The Economics of Biomass Feedstocks in the United States. Biomass Research and Development Board.
60. Sonia Yeh, et al. (2009). Land Use Greenhouse Gas Emissions for Conventional and Unconventional Oil Production. UC Davis.
61. DOC. (2009). "Oil, Gas & Geothermal - DOGGR Home Page." Retrieved, from http://www.conservation.ca.gov/dog/Pages/Index.aspx.

62. Bruce A. Babcock, Dermot J. Hayes, and John D. Lawrence (2008). Using Distillers Grains in the U.S. and International Livestock and Poultry Industries. Midwest Agribusiness Trade Research and Information Center.
63. UN Energy (2007). Sustainable Bioenergy: A Framework for Decision Makers. United Nations Energy.
64. D. J. Tenenbaum (2008). "Food vs. Fuel: Diversion of Crops Could Cause More Hunger." Environmental Health Perspectives 116(6): A254-A257.
65. Food and Agriculture Organization of the United Nations (2008). Soaring Food Prices: Facts, Perspectives, Impacts and Actions Required.
66. Corinne Alexander and Chris Hurt (2007). Biofuels and Their Impact on Food Prices. Purdue University.
67. FAO (2006). The Rise in Crude Oil Prices Stimulates Ethanol-related Dmeand for Agricultural Commodities. Food and Agriculture Organization of the United Nations.
68. D. Keeney (2009). "Ethanol USA." Environmental Science and Technology 43(1): 8-11.
69. NRC (2007). National Research Council: Water Implications of Biofuels Production in the United States. National Research Council.
70. Salil Arora, May Wu, and Michael Wang (2008). Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis. Argonne National Laboratory.
71. R. Righelato and D.V. Spracklen (2007). "Carbon Mitigation by Biofuels or by Saving and Restoring Forests?" Science 317: 902.
72. Michael Sloan (2009). Assessment of Propane Engine Fuel Sales in California. L. Garland.
73. (2000). The American Heritage® Dictionary of the English Language. Houghton Mifflin.
74. UC Berkeley, UC Davis, and LLNL (2008). Guidance Document and Recommendations on the Types of Scientific Information Submitted by Applicants for California Fuels Environmental Multimedia Evaluations. California Environmental Protection Agency.
75. ARB. (2009). "Climate Change Scoping Plan Implementation Update." Retrieved, from ftp://ftp.arb.ca.gov/carbis/board/books/2009/022609/09-2-5pres.pdf.
76. UC Davis (2008). Strategic Development of Bioenergy in the Western States. Western Governors' Association.
77. ARB (2009). Local Air District Rules. Air Resources Board.
78. ARB (2008). 2007 Almanac Emission Projection Data. California Air Resources Board.
79. UN. (2009). "United Nations Environment Programme." Retrieved, from http://www.uneptie.org/scp/.
80. EPFL. (2009). "Roundtable on Sustainable Biofuels." Retrieved, from http://cgse.epfl.ch/page65660.html.
81. UN. (2009). "Food and Agriculture Organization of the United Nations." Retrieved, from http://www.fao.org/.

82. CEC (2007). Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report. California Energy Commission.
83. Michiel J.A. Tijmensen and et al. (2002). "Exploration of the possibilities for production of Fischer Tropsch liquids and power via biomass gasification." Biomass and Bioenergy 23: 129-152.
84. Michael J. Haas and et al. (2006). "A process model to estimate biodiesel production costs." Bioresource Technology 97: 671-678.
85. Y. Zhang, et al. (2003). "Biodiesel production from waste cooking oil: 2. Economic assessment and sensitivity analysis." Bioresource Technology 90: 229-240.
86. Paul W. Gallagher, Heather Brubaker, and Hosein Shapouri (2005). "Plant size: Capital cost relationships in the dry mill ethanol industry." Biomass and Bioenergy 28: 565-571.
87. Sparks Companies (2002). Corn Based Ethanol Costs and Margins. Kansas State University.
88. Robert Wooley and et al. (1999). Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios. National Renewable Energy Laboratory.
89. Hosein Shapouri and Paul Gallagher (2002). USDA·s 2002 Ethanol Cost-of-Production Survey. US Department of Agriculture.
90. Andrew McAloon and et al. (2000). Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks. National Renewable Energy Laboratory.
91. CEC (2007). Natural Gas Fuel Price Forecast. California Energy Commission.
92. IWMB (1989). Statutes of 1989. California Integrated Waste Management Board.
93. David Pimentel and Tad W. Patzek (2005). "Ethanol Production Using Corn, Switchgrass, and Wood; Biodiesel Production Using Soybean and Sunflower." Natural Resources Research 14(1): 65-76.
94. CNN. (2008). "Commodities Pricing." Retrieved, from http://money.cnn.com/data/commodities/.
95. Steve Leer. (2008). "Economist: Take 'stalk' in corn stover as Indiana's ethanol future." Retrieved, from http://www.lafayette-online.com/business/2008/07/corn-stover-ethanol/.
96. NREL (2008). Wood Chips to Heat Laboratories, Save Natural Gas. National Renewable Energy Laboratory.
97. CBOT. (2009). "CBOT Soybean Oil (ZL,ECBOT)." Retrieved, from http://www.tfc-charts.w2d.com/printchart/ZL/C9.
98. Jimmie. (2008). "WVO Yellow Grease price drops." Retrieved, from http://biodiesel.tribe.net/thread/12d12d00-d509-435e-b341-fa459b38decb.
99. CNN. (2009). "Commodities Pricing." Retrieved, from http://money.cnn.com/data/commodities/.
100. Baldemar Ortiz. (2009). "Corn Belt Feedstuffs Wholesale Bids." Retrieved, from http://www.ams.usda.gov/mnreports/sj_gr225.txt.

101. Darren Knop (2009). Freight cost for Ethanol. R. Oineza. Pacific Ethanol.
102. NAP. (2008). "Transitions to Alternative Transportation Technologies: A Focus on Hydrogen." Retrieved, from http://www.nap.edu/catalog.php?record_id=12222.
103. Mike Lewis (2008). E85 Costs. R. Lorestany. Pearson Fuels.
104. Jonathan X. Weinert and Timothy E. Lipman (2006). An Assessment of the Near-Term Costs of Hydrogen Refueling Stations and Station Components. UC Davis.
105. Steven C. Anthony (2008). CNG pricing. R. Lorestany. Sempra.
106. Jill Egbert (2009). Using your information. R. Lorestany. PG&E.
107. USDA (2006). The Economic Feasibility of Ethanol Production from Sugar in the United States. US Department of Agriculture.
108. Fulcrum Bioenergy (2008). Plant to Provide an Attractive Domestic Alternative to High Priced Gasoline.
109. Dr Jeremy Tomkinson Feasibility of a Lignocellulosic Ethanol Facility in the UK. National Non-Food Crops Centre UK.
110. PMAA Excise Tax Counsel Ron Raven and Vice President Holly Tuminello (2005). Important news on Alcohol and Bio-diesel blend tax refund claims. S. Executives.
111. Roger McEowen (2008). Farm Bill Tax Provisions. Iowa State University.
112. Nova Biosource Fuels (2008). Nova Biosource Fuels Applauds Biodiesel Blender Tax Credit Extension. Reuters.
113. RFA (2006). The Enhanced Small Ethanol Producer Tax Credit I.R.C. Sec. 40(b)(3). Renewable Fuels Association.
114. NGV America (2008). Federal Incentive for Alternative Fuel Use/Sale. Natural Gas Vehicles for America.
115. Jason McPhee (2008). Gasoline Dispensing Facility (GDF) Vapor Recovery Hose Population Report. California Air Resources Board.
116. CEC (2001). Costs and Benefits of a Biomass-to-ethanol Production Industry in California. California Energy Commission.
117. FTA. (2009). "Motor Fuel Excise Tax Rates." Retrieved, from http://www.taxadmin.org/fta/rate/motor_fl.html.
118. BOE (2007). Use Fuel Tax Law. Board of Equalization.
119. BOE. (2006). "Detailed Description of the Sales and Use Tax Rate." Retrieved, from http://www.boe.ca.gov/news/sp111500att.htm.
120. BOE (2005). Underground Storage Tank Fee. California State Board of Equalization.

References for Appendices B Through G

Appendix B References:

1. California Board of Equalization. (2008). "Fuel tax rates." Retrieved, from http://www.boe.ca.gov/sptaxprog/spftrpts.htm.
2. EIA. (2007). "U.S. Product Supplied for Crude Oil and Petroleum Products." Retrieved, from http://tonto.eia.doe.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm.
3. CEC. (2009). "California's Oil Refineries " Retrieved, from http://energyalmanac.ca.gov/petroleum/refineries.html.
4. ARB (2007). Emfac 2007. Air Resources Board.
5. Alexander E Farrell, Daniel Sperling, and et al. (2007). A Low-Carbon Fuel Standard for California Part 1: Technical Analysis
6. Antares Group (2008). Strategic Assessment of Bioenergy Development in the West.
7. US EPA (2007). Regulatory Impact Analysis: Renewable Fuel Standard Program. O.o.T.a.A. Quality. 116-170.
8. RFA (2009). Renewable Fuels Association Biorefineries Locations. Renewable Fuels Association.
9. Renewable Fuels Association. (2007). "Renewable Fuels Association Ethanol Industry Statistics." Retrieved, from http://www.ethanolrfa.org/industry/statistics/#E.
10. (2007). Congressional Research Service Report for Congress; Agriculture Based Renewable Energy Production.
11. (2008). Attachment E for Landfill Methane as a Biomass Renewable Energy Source.
12. ARB (1998). Noncombustion Landfill Gas Control Technologies. California Air Resources Board.
13. GTI and Prometheus Energy Company (2007). GTI and Prometheus Energy Company Grant Application Package. California Air Resources Board.
14. Oregon. (2007). "Biomass Energy Homepage." Retrieved, from http://www.oregon.gov/ENERGY/RENEW/Biomass/biogas.shtml#Anaerobic_Digestion.
15. CEC. (2008). "Biomass - Anaerobic Digestion." Retrieved, from www.energy.ca.gov/research/renewable/biomass/anaerobic_digestion/index.html.
16. Hilarides (2007). Hilarides Dairy Grant Application Package. California Air Resources Board.
17. NGSA (2004). Overview of Natural Gas. Natural Gas Supply Association.
18. Michelle Fost (2007). Introduction to LNG. UT Austin.
19. CEC (2009). Significant Events in the History of LNG. California Energy Commission.

20. EIA. (2009). "Natural Gas Plant Processing." Retrieved, from http://tonto.eia.doe.gov/dnav/ng/ng_prod_pp_dcu_nus_a.htm.
21. EIA. (2009). "U.S. Natural Gas Imports by Country " Retrieved, from http://tonto.eia.doe.gov/dnav/ng/ng_move_impc_s1_a.htm.
22. CLNG. (2008). "Bringing LNG to the United States." Retrieved, from http://www.lngfacts.org/LNG-Today/Bringing-LNG.asp.
23. Fritz R. Kalhammer, Bruce M Kopf, and et al. (2007). Report of the ARB Independent Expert Panel. Air Resources Board.
24. CEC (2008). 2007 Net System Power Report. California Energy Commission.
25. CEC (2007). Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report. California Energy Commission.
26. CEC. (2007). "Total Electricity System Power." Retrieved, from http://energyalmanac.ca.gov/electricity/total_system_power.html.
27. CEC. (2008). "Proposed Generation Within the Western Electricity Coordinating Council " Retrieved, from http://energyalmanac.ca.gov/electricity/wecc_proposed_generation.html.
28. Michael Kintner-Meyer, Kevin Schneider, and Robert Pratt (2007). Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids Part 1: Technical Analysis. Pacific Northwest National Laboratory.
29. Lucy Sanna (2005). "Driving the Solution: The Plug-In Hybrid Vehicle." EPRI Journal.
30. Rolf Schreiber. (2008). "Vehicle to grid (V2G) overview." Retrieved, from http://rechargeit.blogspot.com/2008/09/vehicle-to-grid-v2g-overview.html.
31. NAP. (2008). "Transitions to Alternative Transportation Technologies: A Focus on Hydrogen." Retrieved, from http://www.nap.edu/catalog.php?record_id=12222.
32. Carlo N Hamelinck and et al. (2005). "Ethanol from Lignocellulosic Biomass: Techno-Economic performance in Short-, Middle- and Long-Term." Biomass and Bioenergy 28(4): 384-410.
33. S. Phillips, et al. (2007). Thermochemical Ethanol via Indirect Gasification and Mixed Alcohol Sythesis of Lignocellulosic biomass. National Renewable Energy Laboratory.
34. Craig W Rismiller and Wallace E Tyner (2008). Biofuels Comparison Model: Model description and Economic Analysis of Base Case. Department of Agricultural Economics, Purdue University.
35. Renewable Fuels Association. (2008). "U.S. Cellulosic Ethanol Projects under Development and Construction." Retrieved, from http://www.ethanolrfa.org/resource/cellulosic/documents/RFACellulosicPlantHandout.pdf.
36. Sasol Chevron (2008). The Greenhouse Gas Impact of Gas to Liquids (GTL), An Industry Perspective. Chevron.
37. Anders S Carlsson, et al. (2007). Micro- and Macro-Algae: Utility for Industrial Applications. Outputs from the EPOBIO Project.

38. A.B.M. Sharif Hossain, et al. (2008). "Biodiesel Fuel Production from Algae as Renewable Energy." American Journal of Biochemistry and Biotechnology 4(3): 250-254.
39. Jessica M Adams and et al. (2008). "Fermentation Study on Saccharina latissima for Bioethanol." Journal of Applied Phycology.
40. John R Benemann (2008). Microalgae Biofuels: A Brief Introduction.
41. NREL (2008). Photobiological Water Splitting. National Renewable Energy Laboratory.
42. Green Car Congress. (2008). "Sapphire Energy Introduces Algae-Derived Bio-Gasoline." Retrieved, from http://www.greencarcongress.com/2008/05/sapphire-energy.html.
43. CSR Wire. (2006). "Arizona Public Service and GreenFuel Technologies Corp. Successfully Recycle Power Plant Flue Gases into Transportation-Grade Biodiesel and Ethanol." Retrieved, from http://www.csrwire.com/News/6959.html.
44. Robert Buderi. (2007). "Metcalfe Takes Reins at GreenFuel After Key Setbacks; Company Lays Off Half its Staff, Seeks to Raise Cash." Retrieved, from http://www.xconomy.com/boston/2007/07/01/metcalfe-takes-reins-at-greenfuel-after-key-setbacks-company-lays-off-half-its-staff-and-seeks-to-raise-cash/.
45. DOE. (2009). "Alternative and Advanced Fuels, Butanol as an Alternative Fuel." Retrieved, from http://www.afdc.energy.gov/afdc/fuels/emerging_biobutanol_what_is.html.
46. Eric J Steen and et al. (2008). "Metabolic engineering of Saccharomyces cerevisiae for the production of n-butanol." Microbial Cell Factories 7(36).
47. David; Yang Ramey, Shang-Tian (2004). Work performed under contract number: DE-F-G02-00ER86106 for U.S. Department of Energy. US Department of Energy.
48. Jiri van Straelen (2008). CO2 Capture for refineries, a practical approach. ScienceDirect.com.
49. CEC (2007). WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP: SOURCE-SINK CHARACTERIZATION AND GEOGRAPHIC INFORMATION SYSTEM-BASED MATCHING. California Energy Commission.

Appendix C References:

1. TIAX (2007). Full Fuel Cycle Assessment Well to Tank Energy Inputs, Emissions, and Water Impacts. California Energy Commission.
2. Michael O'Hare and et al. (2009). Proper accounting for time increases crop-based biofuels' GHG deficit versus petroleum. UC Berkeley.
3. S. Solomon and et al. (2007). Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Intergovernmental Panel on Climate Change.
4. NASS (2009). Agricultural Prices. US Department of Agriculture.
5. R. Keeney and T. W. Hertel (2008). Indirect Land Use Impacts of US Biofuels Policies: The Importance of Acreage, Yield and Bilateral Trade Responses. GTAP Working Paper 52. Purdue University.
6. USDA (2009). Agricultural Outlook: Statistical Indicators. US Department of Agriculture.
7. Salil Arora, May Wu, and Michael Wang (2008). Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis. Argonne National Laboratory.
8. Kent Tjardes and Cody Wright (2002). Feeding Corn Distiller's Co-Products to Beef Cattle. San Diego State University.
9. R. Lemenager and et al. (2006). The Value of Distillers' Grains as a Livestock Feed. Purdue University.
10. T. J. Klopfenstein (1991). "Efficiency of escape protein utilization." Proc. Distillers Feed Res. Council 46: 77-82.
11. G. L. Cromwell, K. L. Herkelman, and T. S. Stahly (1993). "Physical, chemical, and nutritional characteristics of distillers dried grains with solubles for chicks and pigs." J. Anim. Sci 71: 679-686.
12. F. M. Dong, B. A. Rasco, and S. S. Gazzaz (1987). "A protein quality assessment of wheat and corn distillers dried grains with solubles." Cereal Chemistry 64: 327-332.
13. A. S. Chaudhry and A. J. F. Webster (1993). "The true digestibility and biological value for rats of undegraded dietary nitrogen in feeds for ruminants." 42: 209-221.
14. T. Nakamura, et al. (1994). "Growth efficiency and digestibility of heated protein fed to growing ruminants." J. Anim. Sci. 72: 774-782.
15. S. Uwituze (2008). The effects of feeding dry distiller's grains with solubles on ruminal metabolism, growth performance, and carcass traits of feedlot cattle. Kansas State University.
16. T. J. Vasconcelos and M. L. Galyean (2007). "Nutritional recommendations of feedlot consulting nutritionists: The Texas Tech University survey." 85: 2772-2781.
17. F. J. Dooley (2008). Market analysis for dried distillers grains in Indiana. Purdue University.

18. Michael R. Lehman and Kurt A. Rosentrater (2007). "Microbial development in distillers wet grains produced during fuel ethanol production from corn (Zea mays)." Can J. Microbiology 53: 1046-1052.
19. Kurt A. Rosentrater Ethanol Processing Co-Products: Economics, Impacts, Sustainability. US Department of Agriculture.
20. Mike Deering and Marri Carrow. (2009). "Global Update: February 19, 2009." Retrieved, from http://www.grains.org/global-update/1375-global-update-february-19-2009.
21. CEC. (2008). "Energy Almanac." Retrieved, from http://energyalmanac.ca.gov/.
22. Argonne (2008). The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. Argonne National Laboratory.
23. EPRI (1999). Enhanced Oil Recovery Scoping Study. Electric Power Research Institute.
24. DOC. (2009). "Oil, Gas & Geothermal - DOGGR Home Page." Retrieved, from http://www.conservation.ca.gov/dog/Pages/Index.aspx.

Appendix E References:

1. Susanne Retka Schill (2008). "U.S. ethanol production." Ethanol producer magazine (October).

Appendix F References

1. CEC. (2009). "California's Oil Refineries "   Retrieved, from http://energyalmanac.ca.gov/petroleum/refineries.html.
2. UC Davis (2008). Strategic Development of Bioenergy in the Western States. Western Governors' Association.
3. ARB (2007). Emfac 2007. Air Resources Board.
4. ARB (2009). Emfac Screenshot Table F6-1. California Air Resources Board.
5. ARB (2009). Emfac Screenshot Table F6-2. California Air Resources Board.
6. ARB (2009). GREET Analysis Table F6-3. California Air Resources Board.
7. ARB (2008). California-GREET Model version 1.8b. Air Resources Board. http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.
8. TIAX (2007). Full Fuel Cycle Assessment Well to Tank Energy Inputs, Emissions, and Water Impacts. California Energy Commission.
9. ARB (2007). CALIFORNIA EVAPORATIVE EMISSION STANDARDS AND TEST PROCEDURES FOR 2001 AND SUBSEQUENT MODEL MOTOR VEHICLES. California Air Resources Board.
10. ARB (2008). The California Low-Emission Vehicle Regulations. California Air Resources Board.
11. MSCD (2008). E85 Spreadsheet F6-4. California Air Resources Board.
12. Lisa A. Graham, Sheri L. Belisle, and Cara-Lynn Baas (2008). "Emissions from Light Duty Gasoline Vehicles Operating on Low Blend Ethanol Gasoline and E85." Atmospheric Environment 42: 4498-4516.
13. Renewable Technology (2005). Renewable Diesel Subcommittee of the WSDA Technical Work Group. WSDA.
14. Aaron Williams, et al. (2006). Effect of Biodiesel Blends on Diesel Particulate Filter Performance. SAE.
15. EPA (2002). A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions. US Environmental Protection Agency.
16. Thomas D. Durbin, J. Wayne Miller, Kent Johnson (2009). For the CeCERT Engine Testing portion for the CARB Assessment of the Emissions from the Use of Biodiesel as a Motor Vehicle Fuel in California "Biodiesel Characterization Study" Testing on 2006 Cummins ISM. California Air Resources Board.
17. SAE (2004). Automotive Handbook. Society of Automotive Engineers.
18. William Tahil (2007). The Trouble with Lithium. Meridian International Research.
19. Joyce A. Ober (2008). Lithium. US Geological Survey.
20. USCAR. (2007). "What's recycled more than any other item in the U.S.? Here's a hint -- USCAR's VRP IS involved."   Retrieved, from http://www.uscar.org/commands/files_download.php?files_id=125.
21. Annette Hebert (2008) A-021-0479 Cummins
22. Annette Hebert (2008) A-021-0458-1 Cummins

23. OEHHA (2003). Air Toxics Hot Spots Program Risk Assessment Guidelines. Californa Office of Environmental Health Hazard Assessment.
24. ARB (1998). PROPOSED IDENTIFICATION OF DIESEL EXHAUST AS A TOXIC AIR CONTAMINANT. California Air Resources Board.
25. ARB (2002). Public Hearing to Consider Amendments to the Ambient Air Quality Standards for Particulate Matter and Sulfates. California Air Resources Board.
26. ARB (2007). Health Risk Assessment for the Union Pacific Railroad Commerce Railyard. California Air Resources Board.
27. ARB (2006). Emission Reduction Plan for Ports and Goods Movement in California. California Air Resources Board.
28. ARB (2000). Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles. California Air Resources Board.
29. SCAQMD (2000). MULTIPLE AIR TOXICS EXPOSURE STUDY. South Coast Air Quality Management District.
30. EPA (2004). USER'S GUIDE FOR THE AMS/EPA REGULATORY MODEL - AERMOD. US Environmental Protection Agency.
31. ARB (2007). Health Risk Assessment for the Union Pacific Railroad Commerce Railyard Stationary Source Division. California Air Resources Board.
32. ARB (2006). ARB Almanac 2006. California Air Resources Board.
33. ARB and OEHHA (2002). Public Hearing to Consider Amendments to the Ambient Air Quality Standards for Particulate Matter and Sulfates. California Air Resources Board.
34. ARB (2006). Emission Reduction Plan for Ports and Goods Movement. California Air Resources Board.
35. EPA (2004). Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines. US Environmental Protection Agency.
36. EPA (1999). The Benefits and Costs of the Clean Air Act 1990 to 2010. US Environmental Protection Agency.
37. EPA (2005). Regulatory Impact Analysis for the Final Clean Air Interstate Rule. US Environmental Protection Agency.
38. ARB (2008). Methodology for Estimating the Premature Deaths Associated with Long-term Exposures to Fine Airborne Particulate Matter in California. California Air Resources Board.
39. Alan C. Lloyd and Thomas A. Cackette (2001). "Diesel Engines: Environmental Impact and Control." Journal of the Air & Waste Management Association 51: 809-847.
40. F Diminici and et al. (2005). "Revised Analyses of the National Morbidity, Mortality, and Air Pollution Study: Mortality Among Residents Of 90 Cities." Journal of Toxicology & Environmental Health: Part A 68(13/14): 1071-1092.
41. MEREDITH FRANKLIN, ARIANA ZEKA, and JOEL SCHWARTZ (2007). "Association between PM2.5 and all-cause and specific-cause mortality in 27 US communities." Journal of Exposure Science and Environmental Epidemiology 17(3): 279-287.

42. Michael Jerrett and et al. (2005). "Spatial Analysis of Air Pollution and Mortality in Los Angeles." Epidemiology 16(6): 727-736.
43. C. Arden Pope III, et al. (2002). "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association 287(9): 1132-1141.
44. Mark A. Thayer (2003). The Economic Value of Respiratory and Cardiovascular Hospitalizations. UC San Diego.
45. EPA (2000). Guidelines for Preparing Economic Analyses. US Environmental Protection Agency.
46. Katherine Mrowka (2008). Division of Water Rights, State Water Resources Control Board.
47. Bart Christensen PE (2008). Division of Water Quality, State Water Resources Control Board.
48. Andy Aden (2007). Water Usage for Current and Future Ethanol Production. National Renewable Energy Laboratory.
49. Bureau of Reclamation. (2009). "Central Valley Project - Folsom and Sly Park." Retrieved, from http://www.usbr.gov/dataweb/html/folsom.html.

This Page Left Intentionally Blank

APPENDIX A

PROPOSED REGULATION ORDER

This Page Left Intentionally Blank

PROPOSED REGULATION ORDER

Adopt new sections 95480, 95480.1, 95481, 95482, 95483, 95484, 95485, 95486, 95487, 95488, and 95489, title 17, California Code of Regulations (CCR), to read as follows:

(Note: The entire text of sections 95480, 95480.1, 95481, 95482, 95483, 95484, 95485, 95486, 95487, 95488, and 95489 is new language.)

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

Subarticle 7. Low Carbon Fuel Standard

Section 95480. Purpose

The purpose of this regulation is to implement a low carbon fuel standard, which will reduce greenhouse gas emissions by reducing the full fuel-cycle, carbon intensity of the transportation fuel pool used in California, pursuant to the California Global Warming Solutions Act of 2006 (Health & Safety Code (H&S), section 38500 et.seq.).

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975).

Section 95480.1. Applicability

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

Except as provided in this section, the California Low Carbon Fuel Standard (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.

(b) *Credit Generation Opt-In Provision for Specific Alternative Fuels.*

Each of the following alternative 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. 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, as defined in 13 CCR §1905(a);
(4) Locomotives not subject to the requirements specified in 17 CCR §93117; and
(5) Ocean-going vessels, as defined in 17 CCR §93118.5(d). This exemption does not apply to recreational and commercial harbor craft, as defined in 17 CCR §93118.5(d).

(e) Nothing in this LCFS regulation (17 CCR § 95480 et seq.) may be construed to amend, repeal, modify, or change in any way the California reformulated gasoline regulations (CaRFG, 13 CCR §2260 et seq.), the California diesel fuel regulations (13 CCR §2281-2285 and 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*.*

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 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, or sections 95482 through 95489:

(1) "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).

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

(3) "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 (*Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels*);
(D) Intended for use in engines that are designed to run on conventional diesel fuel; and
(E) Derived from nonpetroleum renewable resources.

(4) “Biodiesel Blend” means a blend of biodiesel and diesel fuel containing 6% (B6) to 20% (B20) biodiesel and meeting ASTM D7467-08 (*Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to 20)*), which is incorporated herein by reference.

(5) “Biogas (also called biomethane)” means natural gas that meets the requirements of 13 CCR §2292.5 and is derived from anaerobic digestion of agricultural waste, animal waste, or other biomass.

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

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

(8) "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) “Biomass-based diesel” means a biodiesel (mono-alkyl ester) or a renewable diesel that complies with ASTM D975-08ae1 (*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) “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.

(11) “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) “Compressed Natural Gas (CNG)” means natural gas that has been compressed to a pressure greater than ambient pressure and meets the requirements of 13 CCR §2292.5.

(13) “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 CO2E, and are calculated pursuant to section 95485(a).

(14) “Diesel Fuel” (also called conventional diesel fuel) has the same meaning as specified in 13 CCR §2281(b).

(15) “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.

(16) “E100,” also known as “Denatured Fuel Ethanol,” means nominally anhydrous ethyl alcohol meeting ASTM D4806-08 (*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) “Executive Officer” means the Executive Officer of the Air Resources Board, or his or her designee.

(18) “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) “Finished fuel” means a fuel that is used directly in a vehicle for transportation purposes without requiring additional chemical or physical processing.

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

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

(22) “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) “Import” means to bring a product from outside California into California.

(24) "Importer" means the person who owns 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) "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(c).

(27) "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) "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) "Liquefied Natural Gas (LNG)" means natural gas that has been liquefied and meets the requirements of 13 CCR §2292.5.

(30) "Motor vehicle" has the same meaning as defined in section 415 of the Vehicle Code.

(31) "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 ICEV uses both electricity and hydrogen as the fuel source and can be "refueled" using two separately distinct fueling ports.

(32) “Multimedia evaluation” has the same meaning as specified in H&S §43830.8(b) and (c).

(33) “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.

(34) “Oil Sands” means sands that are naturally occurring mixtures of sand or clay, water and an extremely dense and viscous form of petroleum called bitumen. They are found in large amounts in many countries throughout the world, but are found in extremely large quantities in Canada and Venezuela.

(35) “Oil Shale” means fine-grained sedimentary rock that contains significant amounts of kerogen (a solid mixture of organic chemical compounds), from which liquid hydrocarbons can be extracted by distillation or other means.

(36) “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.

(37) “Producer” means, with respect to any liquid fuel, the person who owns the liquid fuel when it is supplied from the production facility.

(38) “Production facility” means, with respect to any liquid fuel (other than LNG), a facility in California at which the fuel is produced. "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.

(39) “Public access fueling facility” means a fueling facility that is not a private access fueling dispenser.

(40) “Regulated party” means a person who, pursuant to section 95484(a), must meet the average carbon intensity requirements in section 95482 or 95483.

(41) “Renewable diesel” means a motor vehicle fuel or fuel additive which 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.

(42) “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.®

(43) “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.
(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) “GVRW” 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) “MDV” means medium-duty vehicles.
(22) “MT” means metric tons of carbon dioxide equivalent.
(23) “PHEV” means plug-in hybrid vehicles.
(24) “ULSD” means California ultra low sulfur diesel.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 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(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	94.89	1.0%
2014	94.41	1.5%
2015	93.45	2.5%
2016	92.50	3.5%
2017	91.06	5.0%
2018	89.62	6.5%
2019	88.18	8.0%
2020 and subsequent years	86.27	10.0%

(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	93.76	1.0%
2014	93.29	1.5%
2015	92.34	2.5%
2016	91.40	3.5%
2017	89.97	5.0%
2018	88.55	6.5%
2019	87.13	8.0%
2020 and subsequent years	85.24	10.0%

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975).

Section 95483. Average Carbon Intensity Requirements for Alternative Fuels

(a) The requirements of this section apply to a regulated party that provides an alternative fuel as a transportation fuel in California.

(b) *Carbon Intensity Requirements for an Alternative Fuel Other Than a Biomass-Based Diesel Fuel -Intended for Use in a Single Fuel Vehicle.*

(1) A regulated party must use the average carbon intensity value for gasoline set forth in section 95482(b) for its alternative fuel, other than biomass-based diesel fuel, if the alternative fuel is used or intended to be used in any single-fuel:

(A) light-duty vehicle, or

(B) medium-duty vehicle.

(2) A regulated party must use the average carbon intensity value for diesel fuel set forth in section 95482(c) for its alternative fuel, other than biomass-based diesel fuel, that is used or intended to be used in any single-fuel application not identified in section 95483(b)(1).

(c) *Carbon Intensity Requirements for Biomass-Based Diesel Fuel Provided for Use in a Single Fuel Vehicle.* A regulated party must use the average carbon intensity value for diesel fuel set forth in section 95482(c) if its biomass-based diesel fuel is used or intended to be used in any single-fuel:

(1) light-duty vehicle;

(2) medium-duty vehicle;

(3) heavy-duty vehicle;

(4) off-road transportation application;

(5) off-road equipment application;

(6) locomotive or commercial harbor craft application; or

(7) non-stationary source application not otherwise specified in 1-6 above.

(d) *Carbon Intensity Requirements for Transportation Fuels Intended for Use in Multi-Fuel Vehicles.*

(1) For an alternative fuel provided for use in a multi-fueled vehicle, a regulated party must use:

(A) the average carbon intensity value for gasoline set forth in section 95482(b) if one of the fuels used in the multi-fuel vehicle is gasoline; or

(B) the average carbon intensity value for diesel fuel set forth in section 95482(c) if one of the fuels used in the multi-fuel vehicle is diesel fuel.

(2) For an alternative fuel provided for use in a multi-fueled vehicle (including a bi-fuel vehicle) that does not use gasoline or diesel fuel, a regulated party must use:

(A) the average carbon intensity value for gasoline set forth in section 95482(b) if that alternative fuel is used or intended to be used in:

1. light-duty vehicle, or

2. medium-duty vehicle.

(B) the average carbon intensity value for diesel set forth in section 95482(c) if that alternative fuel is used or intended to be used in an application not identified in section 95483(d)(2)(A).

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 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:

a. the volume and average carbon intensity of the transferred CARBOB; 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.

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:

a. the volume and average carbon intensity of the transferred CARBOB; 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) *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:

a. the volume and average carbon intensity of the transferred gasoline; 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.

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:

   a. the volume and average carbon intensity of the transferred diesel fuel or diesel fuel blend; 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.

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:

a. the volume and average carbon intensity of the transferred diesel fuel or diesel fuel blend; 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) *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 regulated party is determined in the order specified below:

(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*

(1) *Compliance Period.* Beginning in 2011 and every year thereafter, the compliance period is January 1 through December 31 of each year.

(2) *Calculation of 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:

$$CreditBalance = Credits^{Gen} + Credits^{CarriedOver} + Credits^{Acquired} + Deficits^{Gen} - Credits^{Sold} - Credits^{Exported} - Credits^{\mathrm{Re}tired}$$

where:

$Credits^{Gen}$ is the total credits generated pursuant to section 95485(a) for the current compliance period;

$Credits^{CarriedOver}$ is the credits or deficits carried over from the previous compliance period;

$Credits^{Acquired}$ is the credits purchased or otherwise acquired in the current compliance period;

$Deficits^{Gen}$ is the total deficits generated pursuant to section 95485(a) for the current compliance period;

$Credits^{Sold}$ is the credits sold or otherwise transferred in the current compliance period;

$Credits^{Exported}$ is the credits exported to programs outside the LCFS for the current compliance period; and

$Credits^{\mathrm{Re}tired}$ is the credits retired within the LCFS for the current compliance period.

(3) *Deficit Carryover.* A 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 has a credit balance greater than or equal to zero in the previous compliance period; and

(B) the 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.

(4) *Deficit Reconciliation.*

(A) A regulated party that meets the conditions of deficit carryover, as specified in section 95481(b)(3), 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.

(B) If the conditions of deficit carryover as specified in section 95481(b)(3) are not met, 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) *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(c)(3) and 95484(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 To Report.* A regulated party must submit an annual compliance and quarterly progress report 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(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 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 the product transfer document and report the applicable information identified in section 95484(a)(1)(B), (a)(1)(C), (a)(1)(D), (a)(2)(B), (a)(2)(C), (a)(4)(B), (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.

4. 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(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;

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. 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(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.

(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, 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(c)(5)(A) to 95484(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 (*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 for LCFS Transportation Fuels.

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	x	x	x	x	x
Blended fuel (yes/no)	x	x	x	x	x
If yes, number of blendstocks	x	x	n/a	x	x
Type(s) of blendstock	x	x	n/a	x	x
RIN numbers	x	n/a	n/a	n/a	x
Blendstock feedstock	x	x	n/a	x	x
Feedstock origin	x	x	n/a	x	x
Production process	x	x	x*	x	x
Amount of each blendstock (MJ)	x	x	n/a	x	x
**The CI of the fuel or blendstock ($CI^{XD}_{reported}$)	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

** 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) *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 a physical pathway, for each of the transportation fuels and blendstocks for which it is responsible under the LCFS regulation, and that physical pathway has been approved by the Executive Officer pursuant to this section 95484(d)(2).

"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 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 who is expected to transport the fuel through each segment of the physical pathway. The regulated party must provide the name, mailing address, phone number, and company name for each such person.

(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(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(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(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(d)(2)(A) through (C).

“Material change” means any change to the initially submitted information other than a change in the name, phone number, mailing address, or company name for a person identified in section 95484(d)(2)(A).

If there is a material change to an approved physical pathway demonstration, the regulated party must submit for Executive Officer approval new initial demonstrations, pursuant to section 95484(d)(2)(A) through (C), which includes the material change(s) to the physical pathway. For changes that are not material changes, the regulated party must notify the Executive Officer of the applicable change in the person's name, phone number, mailing address, or company name.

(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(d)(2). Upon receiving Executive Officer approval of a physical pathway, the regulated party may claim LCFS credits based on that pathway retroactive to the date use of the pathway began.

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(d)(2)(A) through (D). 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.

(e) *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 (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 Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 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 Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 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, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 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 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[71]:

[71] Energy density factors are based on the lower heating values of fuels in CA-GREET using BTU to MJ conversion of 1055 J/Btu.

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)
Neat denatured 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:

$Credits^{Gen}$ 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) $$Credits_i^{XD} \;/\; Deficits_i^{XD}(MT) = \left(CI_{s\tan dard}^{XD} - CI_{reported}^{XD}\right) \times E_{displaced}^{XD} \times C$$

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");

$CI_{standard}^{XD}$ 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 as per 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 as per 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) $$CI_{reported}^{XD} = \frac{CI_i}{EER^{XD}}$$

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 / ICEV	1.0	CNG or LNG	0.9
Electricity / BEV, or PHEV	3.0	Electricity / BEV, or PHEV	2.7
H2 / FCV	2.3	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 that is not a regulated party or acting on behalf of a regulated party, may not purchase, sell, or trade LCFS credits.

(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 generated outside the LCFS program in the LCFS, 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, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 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 responsible ("regulated party's fuel").

(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 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).

(b) *Method 1 – ARB Lookup Table.*

(1) To generate carbon intensity values, ARB uses the California-modified GREET (CA-GREET) model (version 1.8b), 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 internet site.

Upon adoption of the LCFS, the Executive Officer will certify for use in meeting the requirements of this section an initial set of carbon intensity values for various fuel pathways. This initial set of carbon intensity values will be published in a Carbon Intensity Lookup Table (hereinafter called "Lookup Table"), which will be available on ARB's internet site. Thereafter, the Executive Officer will add to the Lookup Table any new carbon intensity values and their associated pathways, either at the Executive Officer's initiative or Executive Officer approval of a new fuel and pathway proposed by a regulated party pursuant to Method 2A or 2B. Both the initial set of carbon intensity values and subsequently approved new carbon-intensity values will be published in the Lookup Table and made available on ARB's internet site for use as specified in this section.

(2) *Use of Lookup-Table Carbon-Intensity Values.*

(A) *For CARBOB, Gasoline and Diesel Fuel.*

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 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 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.*

Except as set forth in this provision, if 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 oils), the carbon intensity for the regulated party's crude oil must be determined as follows in the order shown:

a. The carbon intensity value shown in the Lookup Table corresponding to the high carbon-intensity crude oil's pathway;

b. Except as provided in c. below, if there is no carbon intensity value shown in the Lookup Table corresponding to the crude's pathway, the regulated party must propose a new pathway for its crude oil 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

c. The regulated party may, upon written Executive Officer approval pursuant to section 95486(f), use the average carbon intensity value in the 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 CO_2e/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 use the carbon intensity value in Lookup Table that most closely corresponds to the production process used to produce the regulated party's fuel. The Lookup Table carbon intensity value selected by the regulated party is subject to approval by the Executive Officer.

For example, if one of the regulated party's fuels is ethanol produced from the fermentation of cellulosic feedstock derived from farmed trees, the regulated party would use the total carbon intensity value in the Lookup Table (i.e., the last column in Lookup Table) corresponding to the applicable Fuel (Ethanol) and Feedstock (Cellulosic, Farmed Trees, Fermentation).

(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, which is incorporated by reference, or other model determined by the Executive Officer to be at least equivalent to the GTAP model.

(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, which is incorporated by reference, or other model determined by the Executive Officer to be at least equivalent to the GTAP model.

(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 is expected 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 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. Any use of a proposed Method 2A or 2B before Executive Officer approval is granted shall constitute a violation of this regulation for each day that the violation occurs. 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 17 CCR §§ 91000-91022 and the California Public Records Act (Government Code section 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 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 calendar 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 internet site and make it available for a minimum 30-calendar day, public-review process. 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.* Within 45 calendar days after the public review process set forth in subsection (f)(3) above ends, the Executive Officer shall take final action to approve or disapprove an application submitted pursuant to this subsection (f). The Executive Officer shall notify the regulated party accordingly and publish the final action on ARB's internet site. If the final action is approval of a new carbon intensity value and associated fuel pathway, the Executive Officer shall update the Lookup Table to reflect the new value accordingly. If the Executive Officer disapproves an application, the disapproval shall identify the basis for the disapproval.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975).

Section 95487. Requirements for Multimedia Evaluation

(a) *Pre-Sale Approval Requirement.*

Except as provided for in section 95487(c), a regulated party must not sell, supply, distribute, import, offer for sale, or offer for use in California a regulated fuel unless one of the following conditions has first been met:

(1) a multimedia evaluation for the regulated fuel has been conducted pursuant to the requirements specified in this regulation, and that evaluation has been approved by the Executive Officer; or

(2) a multimedia evaluation for the regulated fuel has been conducted, and that evaluation was approved by the Executive Officer prior to the date the Office of Administrative Law (OAL) approves the LCFS regulation.

(b) *Requirements.*

(1) The Executive Officer, or his or her designee, shall not approve a multimedia evaluation subject to this section 95487(b) unless the evaluation has undergone the process for review and approval specified in H&S section 43830.8, including but not limited to, receiving peer review and approval by the California Environmental Policy Council pursuant to H&S section 43830.8(d)-(g). For purposes of H&S section 43830.8(a), each Executive Officer approval of a regulated fuel for compliance with the LCFS regulation under section 95487(a)(1) shall constitute compliance with the requirement in H&S section 43830.8(a) for conducting a multimedia evaluation prior to adoption of a “regulation that establishes a specification for motor vehicle fuel.”

(2) All multimedia evaluations subject to this section 95487shall be evaluated in accordance with the California Environmental Protection Agency (Cal/EPA) guidance document entitled, *Guidance Document and Recommendations on the Types of Scientific Information Submitted by Applicants for California Fuels Environmental Multimedia Evaluations (June 2008)*, which can be downloaded at http://www.arb.ca.gov/fuels/multimedia/080608guidance.pdf, and which is incorporated herein by reference.

(c) *Exemptions.*

(1) *Negative Declaration For ARB-Adopted New Or Amended Fuel Specifications*.

The requirements of this section 95487 do not apply to a regulated fuel if:

(A) the regulated fuel is subject to a proposed ARB regulation establishing a new or amending an existing fuel specification, which ARB adopts after the date OAL approves the LCFS regulation; and

(B) the California Environmental Policy Council, following an initial evaluation of the proposed regulation, conclusively determines that the regulation will not have any significant adverse impact on public health or the environment.

(2) *CaRFG, Diesel Fuel, E100, E85, CNG, LNG, and Hydrogen.*

The requirements of this section 95487 do not apply to a regulated fuel if:

(A) the fuel is subject to an ARB-adopted fuel specification; and

(B) the Executive Officer does not amend that fuel specification after OAL approves the LCFS regulation.

Fuels currently subject to this provision include CaRFG, diesel fuel, E100, E85, CNG, LNG, and hydrogen. This provision applies only to the extent that the Executive Officer does not amend the fuel specification for any of the above fuels. When OAL approves an ARB amendment to a fuel specification identified above, this provision shall no longer apply for that fuel.

(3) *Biomass-Based Diesel and Electricity.*

The requirements of this section 95487 do not apply to a regulated fuel that:

(A) is subject to the Division of Measurement Standards' Engine Fuels Standards (4 CCR §4140 et seq.); but

(B) is not subject to an ARB-adopted fuel specification.

Fuels currently subject to this provision include biomass-based diesel, and electricity. This provision applies only to the extent that the Executive Officer does not adopt a fuel specification for any of the above fuels. When OAL approves an ARB-adopted fuel specification for a fuel identified above, this provision shall no longer apply for that fuel.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975).

Section 95488. Cap and Trade

(a) [This section is reserved for future use]

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975).

Section 95489. Regulation Review

The Executive Officer shall conduct a review of the implementation of the LCFS program by January 1, 2012. The Executive Officer shall determine the scope and content of the review.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975). Reference cited: Sections 38501, 38510, 38560, 38560.5, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3rd 411, 121 Cal.Rptr. 249 (1975).