Low Carbon Fuel Standard 2011 Program Review Report

Final Draft

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Special thanks to all of the Advisory Panel members who provided valuable input and recommendations.

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I. *Executive Summary*

A. Overview

In this review report, the Air Resources Board (ARB) staff discusses the mandatory review of the Low Carbon Fuel Standard (LCFS) that was completed pursuant to Section 95489 of the regulation. The report contains the implementation status of the LCFS that ARB staff prepared in consultation with the LCFS Advisory Panel. This report covers a range of topics including opportunities to further harmonize the LCFS with other similar programs within the United States and outside of the country; the supply and availability of low carbon fuels; the ongoing status assessments (including technology, lifecycle, economic, and environmental impacts); potential high-level program enhancements to better ensure that the LCFS long-term targets for 2020 and beyond are met; and alternative approaches for handling High Carbon Intensity Crude Oil (HCICO) under the program.

The focus of the report is the first of two formal reviews of the LCFS that the Executive Officer is required to conduct under the regulation in consultation with the LCFS Advisory Panel. However, in addition to the required formal reviews, staff anticipates providing regular program updates to the Board throughout the program's implementation. For this formal review, the Executive Officer was required to convene an Advisory Panel with which to consult on the review. The Panel consisted of 39 representatives from a broad spectrum of industries and organizations including: the California Energy Commission; the California Public Utilities Commission; fuel providers; storage and distribution infrastructure owner/operators; consumers; engine and vehicle manufacturers; environmental justice organizations; environmental groups; academia; public health; and other stakeholders and government agencies.

The Panel met a total of six times, with three of those meetings spanning two days. During the meetings, the Panel discussed a range of materials that included agendas, outlines, and draft chapters. The work of the Panel was to provide a higher level review of the rule and not to duplicate the efforts of expert workgroups. Panelists were also given opportunities to present their opinions through discussions, outlines, and presentations. Staff made these materials available to the public on the LCFS Advisory Panel webpage,[2] and any interested party could attend the meetings via teleconference or webinar as well as direct questions to the ARB or panelists regarding the program review. After the meetings, staff requested written comments within one to three weeks from panelists and the public on materials presented; staff posted the comments on the LCFS Advisory Panel webpage for public review.

During these meetings, the Panel covered a range of topics that were specified in the regulation to be considered as part of the program review, including:

[2] http://www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/advisorypanel.htm.

- Progress against targets
- Adjustments to the compliance schedule, if needed;
- Advances in full, fuel-lifecycle assessment;
- Advances in fuels and production technologies, including feasibility and cost-effectiveness of advances;
- Availability and use of ultralow carbon fuels, advisability of establishing mechanisms to incentivize the use of higher volumes of these fuels;
- Assessment of supply availabilities and rates of commercialization of fuels and vehicles;
- Program's impact on State's fuel supplies;
- Impact on State revenues, consumers, economic growth;
- Analysis of public health impacts at State and local levels in consultation with public health experts;
- Assessment of the air quality impacts associated with the implementation of the LCFS;
- Identification of hurdles or barriers (e.g., permitting issues, infrastructure adequacy, research funds) and recommendations for addressing such hurdles or barriers;
- Significant economic issues, fuel adequacy, reliability, and supply issues, and environmental issues that have arisen; and
- Advisability of harmonizing with international, federal, regional, and state LCFS and lifecycle assessments.

Many of these topics have overlapping or interconnected elements. Because of these linkages and, in an effort to reduce repetition as well as enhance readability, the report has been structured such that it groups similar and related topics. In some cases where a topic calls out several different broad ideas, those have been split and addressed separately in the appropriate sections of the report.

The Panel provided comments and feedback for staff's consideration. Along with the staff's assessment, the report includes Panel findings and recommendations to the degree that there was general agreement on an issue. These points of agreement were specifically noted in the report to differentiate them from the staff's sole assessments. In order to ensure that the range of viewpoints on any particular subject were adequately represented, ARB staff provided panelists with several opportunities to provide edits and feedback on all documents for which comments were solicited. As noted, however, staff was the final arbiter of content.

Each chapter begins with a description of the topics that are addressed in the chapter, reciting the regulatory text for a clearer understanding of what can be found in each chapter. Each of these chapters addresses the questions called out in the workplan, [3] which was developed in consultation with the Panel and served as a guide for the development of this report. This report represents a compilation of staff recommendations, panelist recommendations, and a summary of the range of panelist opinions based on the topics outlined in the regulation. For several topics, panelists had a broad range of perspectives. For these topics, the objective was not to arrive at a consensus position but rather understand and consider differing viewpoints. Every

[3] http://www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/20110616_workplan_v2.pdf

effort has been made to capture the range of perspectives shared by panelists on the topics discussed in the report.

Another important consideration when reading the report is to recall that implementation of the rule is in the earliest stages of the LCFS program. 2010 was a reporting year only and 2011 is the first year that the LCFS requires a reduction in the carbon intensity (CI) of transportation fuels. Further, the required CI reduction in 2011 is modest, just 0.25 percent. Thus, at this early stage of the program, the discussion of the topics throughout the report reflects, by necessity, the limited amount of available information and history associated with the program's implementation to date.

Overall, the panelists provided thought-provoking conversations and pertinent research that aided staff in assessing the current state of the program, while providing suggestions for staff to move forward with continued monitoring for several aspects of the LCFS program. There were several topic areas where ARB engaged a subgroup of panelists to aid in the development of the chapters. This included the chapters related to economics and credit trading. In addition to these subgroups, there were at least two independently-formed groups that focused on investments and the current state of advanced biofuels (led by Bob Epstein of E2) and flexible compliance mechanisms (led by Chris Hessler of AJW, Inc.). More details regarding these independent groups can be found within the report. Panelists remained engaged throughout the process, providing feedback during meetings and via the web portal. The Advisory Panel added considerable value to the program review. Further, comments from the panelists will help to inform and guide (e.g., identify information to collect, evaluate, and post) further informal reviews as well as the future formal program review.

The next formal review where an Advisory Panel will be convened is scheduled to be completed before January of 2015. However, staff anticipates continuing to engage Panel members and other stakeholders to monitor the progress of the LCFS in a less structured setting prior to the next formal program review and bring periodic updates back to the Board, as appropriate.

B. Topics for Review

1. Harmonization

The concept of harmonizing specific aspects of the LCFS program with other low carbon fuel standard programs has been of interest for the staff since the inception of the program. ARB developed the framework for the LCFS in order for it to be easily exported to other jurisdictions with only minor tweaks. Since the initiation of the LCFS, many other LCFS-like programs have emerged or are being considered both nationally and internationally (e.g., Northeast States, Oregon, the EU, etc.). Some of these are performance-based standards, similar to the LCFS, while others are biofuel mandates that may or may not take into account the full fuel lifecycle analysis. All these programs have potential effects on the LCFS and the movement/use of low carbon fuels around the world. Panelists and staff discussed the advisability of further harmonizing the LCFS with other state, federal, and international policies.

The concept of harmonizing does not necessarily require that fuel-based GHG programs in different parts of the world be identical. Different regional or national programs can exist harmoniously when their program elements reinforce each other, rather than conflict. To this end, the Panel highlighted the potential importance of harmonization in five main areas: lifecycle assessment; the treatment of HCICO and fossil fuels; sustainability principles and criteria; reporting and chain of custody; and uniformity in the credit market. There are some distinct advantages to harmonizing programs related to these areas, including, but not limited to: lower risk of feedstock and fuel shuffling; ability for credits generated in one program to be used in another program; ease of reporting for regulated parties between different programs; and uniformity in the methodology used to evaluate the GHG impacts of transportation fuels, among others.

On the other hand, there are risks associated with harmonizing the LCFS with other programs this early on in process. First, when developing the LCFS ARB determined, following extensive stakeholder consultations, that the most scientifically robust approach to the program was to evaluate fuels on a lifecycle basis. This includes an assessment of both the direct and indirect effects on GHG emissions. To attempt to harmonize with a program that does not include both portions of the lifecycle analysis, would greatly compromise the validity of the GHG reductions that the LCFS is set to achieve. Second, the LCFS is at the vanguard of fuel-based carbon-intensity GHG reduction programs. Because other programs are just as new or even newer, there is no proven path forward that ensures success. Until those other programs become more established and proven, staff believes that it would be premature to alter the LCFS to further harmonize with them.

With that said, and at the panelists' recommendations, we will continue to investigate the benefits and risks of harmonization with other comparable programs as those efforts are more fully developed. ARB has and will continue to work with other jurisdictions, in hopes of eventually harmonizing key elements of the programs, while being mindful of implementing what makes the most sense from California's perspective.

2. Continued Assessments

There are several types of on-going assessments that staff has committed to perform. These include reviewing both internal and external advances in lifecycle analysis (LCA), an assessment of environmental impacts at the local and regional levels, and an economic assessment of the impacts of the program on State revenues, consumers, and economic growth. In addition to these topics, staff is monitoring the program for any issues that have arisen related to unanticipated economic or environmental impacts. It should be noted that staff will monitor these areas through the entire duration of the regulation, not just during the formal review period. For example, in order to ensure the newest and best technology and data are included in the LCA, staff reviews documents submitted by stakeholders regarding custom carbon intensities and continuously evaluates studies published in peer-reviewed journals.

a. Lifecycle Assessment

There are two main components to the fuel-lifecycle assessment: direct and indirect effects. Direct effects are encompassed in the Method 2A/2B process,[4] indirect effects are primarily addressed through the continued development and review of LUC values, based in part on the review conducted by the Expert Workgroup. These activities are a key element of the LCFS regulation. The data inform the carbon intensity for each fuel pathway, which in turn translates into the credits or deficits under the program as a function of volumes introduced into the transportation fuel system. Panelists were interested in establishing whether there have been any advances in the lifecycle analysis arena and if staff had developed criteria for determining whether new studies would be included in our on-going analyses. Panelists were also interested in the impact these advances might have on stakeholders, and how the advances might be incorporated into the regulation while ensuring that there is a balance between incorporating the advances and providing market certainty.

It is staff's current viewpoint that advances related to the direct emission calculations are mostly updates to data (i.e., model inputs), but that the basic methodology to performing the analysis does not vary significantly from model-to-model. So even though other programs calculate GHG emissions using models different from that of the California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) model, the fundamental way that they function is similar. Thus, staff is not considering any changes in the current modeling approach and does not intend to adjust established direct CI values on a set schedule, but will consider new information as appropriate and adjust model outputs as appropriate. For example, when applicants submit their applications for custom CI values, staff verifies the data submitted by the applicant, which is generally the most current data available. For these examples, staff will consider updating existing direct CIs to the extent applicable and if there are substantial improvements in the available data. Any proposed changes would be evaluated as part of an open public process.

Staff does not expect that the methodology for the estimation of direct emissions for fuel pathways to significantly change in the near future. Should the CA-GREET model be modified to the extent that significant changes are introduced, or a better model is developed, staff will take these changes into consideration and recommend revisions to the fuel pathway CI values in the Lookup Tables as warranted. If ARB makes modifications to CI values in the Lookup Tables due to advances in lifecycle analysis, and those modifications impact the LCFS compliance schedule, the revised CI values would presumably take effect at the beginning of a new compliance period (i.e., January 1st) for ease of implementation.

For the most widely used crop-based biofuels, indirect effects are calculated using the Global Trade Analysis Project (GTAP) developed by researchers at Purdue University. ARB staff previously formed an Expert Workgroup (EWG) to discuss high-level issues and then develop key strategies to address these issues. These included: elasticity values; co-product credits; land cover types; uncertainty in land use change estimates;

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[4] http://www.arb.ca.gov/fuels/lcfs/2a2b/2a-2b-apps.htm

indirect effects of fuels other than biofuels; carbon emission factors; time accounting; and comparative and alternative modeling approaches. In addition to the EWG, there were several independent reviewers who provided input on the details related to these calculations. Staff has been moving forward using a combination of EWG recommendations, independent reviewer recommendations, and staff recommendations. In addition to continuing review of peer-reviewed literature and managing a contract with Purdue University, staff will work with key stakeholders in developing additional indirect effects values in order to ensure that the LCFS accounts for all GHG emissions. Indirect effects other than LUC are being explored by the sustainability working group.

ARB staff understands that there must be a balance between improvements in lifecycle assessment modeling and the need for market certainty because changes in the calculation of a fuel's carbon intensity can significantly affect that fuel's value in the LCFS. We believe that the requirement for periodic program reviews, the deliberate and measured response of ARB to new studies and model updates, the public process used by ARB for changing LUC carbon intensity values and compliance schedule targets, and the Method 2 certification process should provide both an appropriate degree of market certainty while maintaining the scientific foundation of the LCFS and providing flexibility for fuel producers. That is, Method 2 applicants with complete and fully documented submittals will be able to expeditiously receive a direct carbon intensity value that is representative of their fuel pathway, while the process for evaluating the indirect effects due to land-use change and reflecting those effects in the LCFS standards undergoes a more time-consuming process that is required for such a key element of the program.

b. Economic Assessment

Many of the assumptions and information used in the economic analysis of the original LCFS ISOR remains valid. However, due to changes in the rates of advancement of different alternative fuels and to differing tax, subsidy, technology, and overall cost structures, an updated economic analysis is warranted.

As in the original analysis, this update compares the estimated costs of producing petroleum-based transportation fuels with corresponding cost estimates for alternative fuels. This analysis does not attempt to account for carbon-intensity-based price effects. Having examined existing fuel price data, staff has concluded that sufficient information on which such an accounting could be based does not yet exist. ARB staff will continue to work with the California Energy Commission (CEC) and other interested stakeholders to refine the LCFS economic analysis so that it accounts for carbon intensity effects, the termination of tax subsidy and tariff programs, and other factors.

The results of the economic analysis suggest that the estimated production costs of gasoline substitute fuels may have little impact on the cost of the LCFS program, but the production costs of alternative diesel fuels could increase costs to the LCFS in the later years of the regulation

c. Environmental Assessment

Through this review process, staff has determined that the public health and air quality impacts estimated in 2009 have not changed significantly throughout the first implementation year of the LCFS. Any changes that may have occurred are due to many factors, including only slight changes in California's transportation fuel consumption, which cannot be attributed to the LCFS; no new biofuel facilities being built in the State since the 2009 environmental impacts analysis; and no new biofuels that could potentially be used in the State triggering the multimedia evaluation process. As suggested, because 2011 is the first implementation year, the program is still in its infancy. Thus, should there be changes (beneficial or adverse) in response to the LCFS, it is anticipated that they would be relatively minor.

Staff has developed two methods to help ensure the preservation of air quality due to changes in the transportation fuel sector that could occur, at least in part, as a result of the LCFS. The first method includes a biorefinery siting guidance document[5] for local air districts, other agencies, and community members to use to help minimize air pollution from biorefineries. For the second method, staff will fulfill the directive from the Board to participate in the environmental review of proposed projects, working with local air districts and others. Staff is also working with a group of stakeholders on developing a set of voluntary sustainability principles and criteria that may lead to a lower-impact fuel pool.

3. Supply and Availability

The information presented in this report informs many of the illustrative scenarios that ARB staff evaluated as part of this 2011 formal program review. Most of the data comes from the California Energy Commission forecasting in the 2011 IEPR.[6] Staff also considered other data sources, such as the Energy Information Administration data regarding cellulosic ethanol and biofuels, as well as independent reports including those generated by panelists. There were several key questions that emerged when looking at this data, including: Will there be sufficient supplies of low carbon fuels to meet the standard in the near-term and the long-term? What types of investments are flowing to these fuels? And, does the LCFS have an impact on the investment in these fuels?

First, staff focused on the past consumption of transportation fuels to see if there were any significant changes in volumes of fuel consumed prior to 2010. It was apparent from the data that in 2008 there was a slight decrease in the volume of major transportation fuels consumed in the State, with the exception of increased volumes of ethanol. The increase in ethanol consumption is mainly due to the fact that California fuel producers transitioned from E6 to E10 by 2010. Staff does not believe that these slight variations were impacted by the LCFS as the small fluctuations can be attributed to factors outside of the LCFS, such as the economy.

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[5] The draft guidance is expected to be finalized in late 2011 and is available at http://www.arb.ca.gov/fuels/lcfs/bioguidance/docudrafty.pdf.

[6] http://www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf.

Second, as noted later in this summary, staff evaluated the volume of LCFS credits generated to date. Based on data in the LCFS Report Tool (LRT), we note that there are substantially more credits in the market currently than there are deficits. Staff's analysis of first three quarters of 2011 data show that there are about 450,000 MT of CO_2e "net" credits (more credits than deficits generated) registered in the LRT. Further, staff's preliminary analysis of second and third quarter 2011 data suggests that the number of net credits has increased significantly relative to the first quarter. The increase in net credits is an indication that the fuel industry is on track to meet or exceed its compliance obligations for 2011. Because credits are based on the sale of lower CI fuels in California, the net surplus of credits generated to date is further evidence that fuel availability and supply is not currently an issue[7].

Staff also included an assessment in this report regarding the future demand of transportation fuels. Much of this forecasted data originated from the 2011 IEPR as well as from the 2011 Energy Information Administration Annual Energy Outlook.[8] These data were used in a subsequent chapter to present a set of illustrative scenarios that we will discuss later in this summary.

In 2009, the illustrative scenarios evaluated as part of the LCFS rulemaking assumed, in part, that California's "proportional share" of the RFS2 cellulosic ethanol volume mandate would be used in California. Because the EIA has lowered its projected volumes significantly, staff initiated a re-evaluation of the illustrative scenarios. The re-evaluation is discussed in the "Meeting the Targets and Assessment of Whether Adjustments Are Needed" chapter of this report." The main conclusion from the re-evaluation is that, even with a lowering of projected cellulosic ethanol volumes, that stakeholders have various plausible options to meet their compliance obligations.

From a series of discussions among panelists, it became clear that the advanced biofuel industry is a new sector with many potential market entrants and players. As can be expected in an emerging industry, the number of advanced biofuel companies is rapidly changing. The Cleantech Group forecasts the U.S. market of low-carbon fuels at $33 billion by 2020. The forecast is nearly double the future market of energy efficiency ($17 billion), and significantly higher than renewable electricity ($20 billion).[9] To seize this opportunity, venture capitalists have invested at least $1.8 billion in active North American biofuel companies from 2007 through the first quarter of 2011, according to publicly available data. Such a level of investment in the biofuel sector reflects the willingness and confidence investors have in funding the eventual production and commercialization of advanced biofuels. Regulation, including both the RFS2 and LCFS, were highlighted by both biofuel panelists and the Cleantech Group report as the driving force for this investment to date. However, more investments will be needed for next generation biofuels to be commercially produced at high volumes.

The Panel also discussed the advisability of including a provision in the regulation to

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[7] Use of HCICO may affect ability to bank credits for use in later compliance years, however no HCICO have been reported in the LRT for Q1-Q3 2011.

[8] http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf.

[9] Cheng, David, "California in Perspective- A Review of State Energy Policies and Their Impact on High Growth Cleantech Markets." Cleantech Group, 2010.

incentivize ultralow carbon fuels however, the panel did not come to consensus on what exactly comprises an ultralow carbon fuel. Though some panelists were not receptive to the idea of incenting ultralow carbon fuels at this time, staff committed to keeping the dialogue open on this issue.

4. Long-Term Achievement of Goals for 2020 and Beyond

All the topics called out by the regulation for the formal reviews were identified to help ensure that implementation of the program made concrete progress toward achieving the LCFS goals. There were several topics that were specific to the ability for the program to reach the 2020 target and beyond, including a review of meeting the targets, whether program adjustments are needed to help achieve those targets, and the design considerations for the development of an active, robust credit market.

As a starting point, staff's evaluation of the illustrative scenarios developed for this report suggests that there are numerous scenarios that can be employed by stakeholders to comply with the program.[10] Because the LCFS is non-prescriptive relative to the type of fuels used, regulated parties could choose to comply with LCFS targets through any number of technologies. Therefore, these scenarios only attempt to identify some possible paths, but do not attempt to predict actual compliance methods. Staff looked at sixteen illustrative scenarios during the current review – eleven gasoline and five diesel scenarios – based on various assumptions about fuel producer responses to the compliance schedules. For example, some gasoline scenarios were based on lowered cellulosic ethanol projections, increasing numbers of flexible-fueled vehicles, and assumptions about "drop-in" renewable gasoline. On the diesel side, a number of the scenarios were based on increasing market penetration of biodiesel and renewable diesel (up to 20 percent blends by 2017). Many of the illustrative scenarios for both gasoline and diesel showed producers could generate a substantial number of excess credits in the early years, which could be banked for use in the later years (2018-2020). Overall, these illustrative scenarios showed a variety of plausible paths to meeting the LCFS targets.

Staff's evaluation of the illustrative scenarios developed for this report also looked at whether compliance could still be met in spite of smaller volumes of very low-carbon fuels coming into the market at a slower pace. One potential step suggested by some panelists to counteract such a situation would be to make adjustments to the compliance schedule delaying the more stringent reductions until later in the program. However, as noted earlier, the program is in its infancy. In staff's view, adjustments to the compliance schedule at this stage in the program would be premature, unwarranted, and likely harmful in terms of undermining the certainty needed by investors looking to make long-term investments in low CI biofuels. Many panelists have expressed support for this position. After several robust discussions, presentations, and a report on both the health of the advanced biofuels market and investment needed for these low carbon fuels, staff concluded that adjusting the program targets would be counter-productive to incenting the investment needed to commercialize next generation, very low carbon fuels. This led to a discussion on other ways to increase investment in low carbon fuels.

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[10] See "Meeting the Targets and Assessment of Whether Adjustments Are Needed" chapter of this report.

This could include utilizing the credit market to help spur certainty and investment, the concept of a flexible compliance mechanism to address potential short-term market challenges.

a. *Meeting the Targets and Compliance Schedule*

In 2009, staff produced a set of illustrative scenarios as part of the original LCFS staff report. These estimates relied on California receiving its proportional share of the cellulosic volumes originally mandated in the RFS2. Since that staff report, the early years (2009 -2011) mandated and projected volumes have drastically been reduced from the levels set by Congress. This action led to conclusions by some that complying with the LCFS would require approaches completely different than originally envisioned or may not be possible without such fuels becoming available at the volumes originally estimated.

Because of these changes in cellulosic ethanol projections, staff prepared a new set of illustrative scenarios that show a variety of ways that regulated parties can comply with the regulation through 2020. The revised scenarios were based on data gathered for the supply and availability chapter and through coordination with other ARB programs, the California Energy Commission, and the EIA. The most conservative of these illustrative scenarios rely on regulated parties exceeding compliance requirements. This leads to credit generation in the early years of the regulation in order to see them through the more challenging years later in the decade. Other, more aggressive (these more aggressive scenarios are dependent on the availability of next generation low carbon fuels), illustrative scenarios suggest that compliance can be met through 2020 and beyond, using a diverse pool of lower carbon fuels.

Panel members had different viewpoints on the ability of fuel producers to meet the targets and compliance schedules. For example, petroleum fuel providers believed that there were not enough low carbon fuels available to meet near-term goals, while biofuel and alternative fuel providers believed that there was plenty of opportunity to generate credits using fuels that are currently available. There were also several panel members who provide fuels that are currently banking credits in the system.

Though staff believes that these illustrative scenarios are plausible and feasible, some panelists suggested that ARB consider a flexible compliance mechanism should regulated parties, in general, be unable to meet their compliance obligations in a given compliance period due to a limited supplies of low carbon fuels or LCFS credits in the market. One objective of a flexible compliance mechanism would be to provide greater confidence in near-term investment decisions that are predicated on a sustained requirement that the anticipated amounts of low carbon fuels will be required in later years and that the LCFS compliance obligation will be maintained. Staff agreed to take a closer look into such a mechanism as part of this review and make a preliminary determination if such an option has merit sufficient to warrant further investigation for possible inclusion within the LCFS program in the future.

Staff asked interested panelists to conduct an analysis to identify the elements of what the panelists believe are appropriate flexible compliance mechanisms. Unless there is a general, overall shortage of credits, the flexible compliance mechanism would not be invoked, as it would be more economically efficient for operators to meet their obligations via low carbon fuel supply and/or credit purchase. The suggested concept of a flexible compliance mechanism should be constructed in a manner that encourages compliance through credits generated with actual reductions and would only come into play when adverse market conditions occur. The flexible compliance mechanism would provide regulated parties that could not otherwise obtain sufficient credits from the credit market with a short-term alternative with which to comply. One such set of circumstances could occur if the credit market is short at some point in the program; several panelists suggested a flexible compliance mechanism that might, for example, be set up to enable regulated parties to obtain sufficient credits at a known price until the needed credits can be generated.[11]

Based on data in the LCFS Report Tool (LRT), we note that there are substantially more credits than there are deficits. However, the fact that the credit market is well supplied at this stage does not lead to the conclusion that it is premature to take measures to reduce the risk of, and deal with, the potential for future fuel and/or credit supply shortages.

Therefore, staff have concluded that such an option has sufficient merit to warrant further investigation for possible inclusion within the LCFS program. Given the lead times that may be required to commercialize additional supply of low carbon fuel, this work should be undertaken as quickly as feasible. Therefore, staff anticipates following up with stakeholders in early 2012 to further investigate the feasibility of developing the concept of a flexible compliance mechanism.

b. Credit Market

The LCFS is predicated on the ability of regulated parties to access a robust credit market where they can buy and sell credits with ease and confidence. Such transactions need to occur in an environment with sufficient transparency to avoid or detect fraud or other transactional issues. To this end, the short-term goal would be to identify structural design elements that can improve the credit accounting and security of the trading program under development. In general, panel members believe that, as soon as practical, ARB should ensure that the market structure is further refined to encourage, through clear market signals, a healthy and robust system of credits and transactions. Many panelists expressed urgency regarding the development of a viable credit market. The Panel was interested in establishing what types of information would be necessary to evaluate the health of the LCFS credit market, what information should be made available to the public versus what should be collected, but kept confidential, and defining key elements to the credit trading platform.

While the existing LCFS regulation already allows credit trading between regulated parties, establishing the specific “ground rules” that govern trading in LCFS credits will

[11] One example suggested by panelist Bob Epstein (E2) and others, citing a recent example in the state of Hawaii, would involve the State of California receiving LCFS credits through a contract to supply the State’s vehicular fleet with lower-CI fuels. A potential use of such credits would be for strategic easing of credit market fluctuations at pre-determined credit prices.

help create a favorable market trading framework. In turn, a favorable market trading framework would help make the credits more accessible for purchase by regulated parties who need such credits to meet their obligations. To this end, staff has developed specific credit trading provisions to be proposed for the Board's consideration at its December 2011 hearing. Developed in consultation with stakeholders, the proposed credit trading provisions are intended to establish the ground rules for credit trading in the LCFS market and to help foster robust trading between regulated parties.

There were several overriding market design themes stressed by some panelists for consideration by ARB in the short and long-term. First, panelists suggested a variety of existing credit markets that ARB can draw on, in terms of systems that are currently working and how third party providers run them on behalf of public agencies. These were highlighted as ways that ARB could rapidly adapt and deploy a system, as well as systems whose design elements allow ARB to avoid a growing administrative burden as the LCFS market develops.

Second, panelists expressed the need for the LCFS credit market to provide regulated parties with real-or near real-time pricing information. Real-or near real-time pricing information would entail frequent publications by ARB (more frequent than the currently planned quarterly reports), which would help regulated parties seeking to buy or sell credits to identify an appropriate price for such credits at any given time. While staff agrees that the frequent publication of price and other credit-related information would likely be helpful, the LRT is not currently set up to provide this level of information at such frequencies. Thus, staff will need to work with stakeholders to incorporate this feature into future generations of the LRT. Some panelists emphasized that it would be important to ensure that price data provided an accurate reflection of the full value of LCFS credits, given that in some supply deals the prices of the fuel and the associated credits might not be easily separable.

Another design theme advocated by some panelists is the expansion of the LCFS credit market to the so-called secondary market. The current regulation limits credit buying and selling to LCFS regulated parties. The proposed expansion into the secondary market would permit, for example, credit brokers, speculators, and other "willing participants" to trade credits. Some panelists suggested this would theoretically spur investments in advanced biofuels and other low-CI fuels by monetizing the credits. However, as noted earlier, the program is in its infancy, and staff believes that the expansion of trading to the secondary market would entail substantially larger State resources to verify, account, and track the generation and disposition of valid LCFS credits and to provide the necessary oversight to prevent the creation and propagation of fraudulent credits. Thus, staff believes it is premature at this time to expand the market as suggested, however staff will continue to work with stakeholder to explore this option.

In the near term, ARB is conducting a rulemaking in December 2011 to add credit banking, trading, and retirement provisions to the LCFS program. Staff plans to present recommended language to the Board for consideration at its December 2011 hearing. These provisions, developed in consultation with stakeholders, would define how a credit is generated during a quarterly period after a regulated party has reported their progress to ARB. Another provision would provide regulated parties with the ability to purchase in the first quarter of a compliance year "carry-back" credits from a prior compliance period to meet the prior annual compliance. A third provision would specify the transactional information ARB will require before approving the transfer of credits in the reporting tool. Moreover, staff's proposal would specify the required public disclosure that will ensure a healthy and informed market atmosphere.

5. HCICO

The HCICO provision currently in the regulation was established to ensure that the ten percent reduction goal of the LCFS program would not be diminished if there is an increase in the high carbon-intensity of crude oils used by California refineries (and the resulting gasoline and diesel carbon intensity). The inclusion of HCICO provisions in the LCFS regulation recognizes that some crude oils require additional energy to produce (e.g., bitumen mining or thermally enhanced oil recovery techniques) or emit higher levels of GHG emissions during the production process (e.g., excessive flaring), significantly beyond the average carbon intensity value used in the baseline. A performance-based accounting system is necessary to ensure that additional emissions from California's diesel and gasoline fuel are identified and mitigated. A second goal of the HCICO provision is to provide an incentive for oil producers that could supply higher carbon intensity crudes to California refineries to employ emission reduction measures such as reducing flaring, improving energy efficiency, and using carbon capture and sequestration.

Petroleum refiners in California assert that the current HCICO provisions are overly burdensome to their industry, discriminatory toward sources of crude oil, will increase the potential for global crude-shuffling, which they contend would increase GHG emissions, and would put California refiners at an economic disadvantage to out-of-state refiners. Therefore, they have requested that the CI values for CARBOB and diesel in the Lookup Tables of the current regulation be used, regardless of the type of crude supplies used by a refiner (i.e., no differentiation between the carbon intensities of crude oils).

On the other hand, other stakeholders are equally as adamant that the LCFS should continue to account for increases in lifecycle carbon emissions that could occur if higher-intensity crudes are used to replace existing supplies. They assert that: absent a HCICO provision, increased use of HCICOs would largely offset the emission benefits of increased use of low carbon fuels; ignoring increased emissions from HCICOs would be discriminatory and unfair toward low-carbon fuels treated with full lifecycle accounting; no incentive would exist for oil companies to innovate and improve their upstream practices; and California would be sending an inappropriate environmental signal to other jurisdictions pursuing a similar approach. They also argued that crude shuffling already occurs in the industry and that a performance-based approach treats foreign and domestic producers equally.

At the July 1, 2011, Advisory Panel meeting, staff presented five potential options for addressing HCICO in the LCFS. Representatives of the environmental community and the oil industry also made presentations related to the environmental and economic impacts of excluding or including HCICO provisions in the LCFS. Panelists discussed each of the viewpoints presented, and staff committed to continue working with interested stakeholders on possible regulatory amendments to the HCICO provisions in the current LCFS regulation.

Staff has continued working with stakeholders on regulatory revisions for addressing HCICO, including discussing the various approaches suggested by staff and stakeholders. We have also shared guiding principles for considering HCICO amendments, including: seeking an accurate accounting for emissions from production of crude oil; discouraging potential increases in emissions; promoting innovation for emission-reduction activities; and discouraging the potential for crude shuffling to generate credits, avoid deficits, or otherwise comply with the regulation[12].

Currently, ARB staff has proposed amendments to the HCICO provisions in the LCFS for consideration by the Board at its December hearing. Staff will continue working with stakeholders on possible revisions to staff's current proposal leading up to that Board hearing.

C. Summary and Next Steps

This final report represents a compilation of staff views and recommendations, along with panelist recommendations, and a summary of the range of panelist opinions, when applicable, based on the topics outlined in the regulation.

The Advisory Panel engaged in thoughtful discussions on a broad range of topics required to be addressed by ARB staff as part of the program review. Panelists also provided input on additional topics areas. As previously indicated, the considerable value of the Panel was the differing viewpoints on the issues discussed. Comments and suggestions made by panelists are already being reflected in several actions being taken by staff including some of the proposed amendments that the Board will consider in December.

As noted earlier, the LCFS program is in its infancy. Based on our assessment, staff does not believe there have been any significant adverse impacts on the environment in response to the LCFS. Further, staff's re-evaluation of the illustrative scenarios suggests that there are numerous plausible scenarios that can be employed by stakeholders to comply with the program. Based on staff's analysis of the first two quarters of 2011, there are substantial numbers of excess credits in the market, which can potentially help regulated parties in future years meet their compliance obligations; though early, the program is working as intended.

In the long run, next-generation very-low carbon fuels will be needed. As such fuels are several years away, the program needs to maintain its "back-loaded" design features that allows time for the necessary investments in this emerging market of low CI biofuels. Staff also believes that ongoing monitoring of the implementation of the

[12] See advisory 10-04A for guidance on how to handle HCICO for 2011 and 2012.

program is critical. Specifically, staff has many commitments including on-going monitoring of several aspects of the program that will ensure effective program implementation including future recommended regulatory amendments if necessary.

The next formal review of the LCFS is required to be completed by January 2015. Per panelist recommendations, staff will continue to work with stakeholders on informal reviews and staff will provide updates to the Board periodically prior to the next formal review. We anticipate continuing discussions with panelists over the next several years. We also anticipate establishing an Advisory Panel in 2014 to assist with the next formal review. By the next review, additional data should be available to inform a more quantitative analyses of the topics evaluated in this report and new topics might have elevated importance.

II. Background on the 2011 LCFS Advisory Panel

A. Introduction

On April 23, 2009, the California Air Resources Board (ARB or Board) approved the Low Carbon Fuel Standard (LCFS) regulation for adoption. The regulation became effective on April 15, 2010.

The California LCFS is performance-based and is designed to reduce GHG emissions intensity from transportation fuels by 10 percent by 2020. The regulation establishes annual performance standards that fuel producers and importers must meet beginning in 2011. The LCFS applies, either on a compulsory or opt-in basis, to all fuels used for transportation in California. These transportation fuels include California reformulated gasoline, California ultra-low-sulfur diesel fuel, E85, compressed or liquefied natural gas, biogas, electricity, and compressed or liquefied hydrogen.

The metric for California's LCFS is carbon intensity (CI), and it is expressed in terms of grams of CO_2 equivalent per mega-Joule (gCO_2e/MJ). CI is based on the premise that each fuel has a "lifecycle" GHG emissions value. The lifecycle analysis (LCA) of petroleum-based fuels, also known as well to wheel analysis (WTW), estimates the GHG emissions associated with crude recovery, crude transportation, fuel production, fuel transportation, and use of low carbon fuels in motor vehicles. The LCA of biofuels estimates the GHG emissions associated with feedstock production, feedstock transportation, fuel production, fuel transportation, and use of low carbon fuels in motor vehicles. The LCA includes both direct and indirect emissions associated with producing, transporting, and using the fuels. Land use change effects, both direct and indirect, are also considered in CI valuation.

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. Regulated parties use an interactive, secured Internet web-based form, such as the LCFS Reporting Tool (LRT), to submit quarterly status reports and an annual compliance report. They report all fuels introduced into the California transportation fuel system and track the fuels' CI through a system of "credits" and "deficits." Credits are generated from fuels with lower CI than the standard for either gasoline or diesel (95.86 or 94.71 gCO_2e/MJ respectively). Deficits result from the use of fuels with higher CI 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 CI 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 California LCFS provides added flexibility for the regulated parties. The regulation is performance-based, and fuel providers have several options. Fuel providers may incorporate new or improved technologies in fuel production to existing pathways to reduce the CI of their fuels (Method 2A). They may also develop new pathways (Method 2B).

Section 95489 of the regulation requires the Executive Officer to conduct two reviews of the LCFS program in a public process. These reviews will address a broad range of implementation topics and may include recommended amendments to the regulation. Staff will present the results of these reviews to the Board by January 1, 2012, and January 1, 2015.

To assist with the reviews, the Executive Officer is required to convene an Advisory Panel with which he will consult on the reviews. The regulation specifies that the Panel should include representatives of the California Energy Commission; the California Public Utilities Commission; fuel providers; storage and distribution infrastructure owner/operators; consumers; engine and vehicle manufacturers; environmental justice organizations; environmental groups; academia; public health; and other stakeholders and government agencies, as deemed appropriate by the Executive Officer.

Staff initiated the process by soliciting prospective panelists in a process that included distributing a notice[13] via the "LCFS" and "fuels" listserves and posting the application for the Panel on ARB's LCFS public web page. About 60 applications were submitted by various stakeholders. ARB staff recommended prospective panelists based on several factors, including experience of the applicant, the organizations represented in order to establish a broad base of representation, and supporting documentation such as letters of recommendation. Staff recommendations were shared with the Executive Officer and interested Board members before being finalized. Thirty nine stakeholders were ultimately selected for the Panel, along with four alternative members.

Over the course of a year, the Panel met a total of six times, with three of those meetings spanning two days. During these meetings, the Panel was presented with a range of materials that included agendas, outlines, draft chapters, and presentations made by individual panelists that reflected their perspectives. These materials were made available to the public on the LCFS Advisory Panel webpage,[14] and the meetings could be attended by any interested party via teleconference or webinar. After the meetings, panelists and the public were given anywhere from one to three weeks to provide written comments on materials presented; the comments received were posted on the LCFS Advisory Panel webpage for public review.

The final report represents a compilation of staff views and recommendations, along with panelist recommendations, and a summary of the range of panelist opinions, when applicable, based on the topics outlined in the regulation.

[13] http://www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/082310advisory_panel_invitation.pdf.
[14] http://www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/advisorypanel.htm.

B. Panel Composition

Following the solicitation for Panel participants, interested organizations and individuals submitted applications, curricula vitae, and letters of recommendation. With input from Board members, ARB staff selected the panelists from the application pool with expertise in the areas to be reviewed.

As specified in the regulation, the solicitations for the Panel participants were sent to representatives from the California Energy Commission; the California Public Utilities Commission; fuel providers; storage and distribution infrastructure owners/operators; consumers; engine and vehicle manufacturers; environmental justice organizations; environmental groups; academia; public health; and other stakeholders and government agencies, as deemed appropriate by the Executive Officer.

Members of the Panel, including their affiliation, are shown on the LCFS Advisory Panel webpage previously noted.[15]

C. Public Involvement

As noted, all Panel meetings were open to the public and appropriate time periods were set aside for members of the general public to speak. Further, stakeholders were encouraged to submit written comments through the Panel's website noted previously.

ARB staff developed this report of findings with recommendations based on panelist and public feedback. This report includes not only staff recommendations but also panelists' recommendations and, when appropriate, a spectrum of panelist opinions on the range of topics covered by the review. This review process provided staff with invaluable insight on how the LCFS program is moving forward and elements that could be strengthened to improve and secure the longevity and the benefits of the LCFS.

D. Scope of Work

The Panel discussed and provided input on issues focusing on the implementation of the LCFS. Those topics included those called for in section 95489(a) of the regulation which defined the minimum scope of the two required program reviews. Each review is to include the following topics:

(1) The LCFS program's progress against LCFS targets;
(2) Adjustments to the compliance schedule, if needed;
(3) Advances in full, fuel-lifecycle assessments;
(4) Advances in fuels and production technologies, including the feasibility and cost-effectiveness of such advances;
(5) The availability and use of ultralow carbon fuels to achieve the LCFS standards and advisability of establishing additional mechanisms to incentivize the use of higher volumes of these fuels;

[15] Panelists are listed in http://www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/membersv.4.pdf.

(6) An assessment of supply availabilities and the rates of commercialization of fuels and vehicles;
(7) The LCFS program's impact on the State's fuel supplies;
(8) The LCFS program's impact on State revenues, consumers, and economic growth;
(9) An analysis of the public health impacts of the LCFS at the state and local level, including the impacts of local infrastructure or fuel production facilities in place or under development to deliver low carbon fuels, using an ARB approved method of analysis developed in consultation with public health experts from academia and other government agencies;
(10) An assessment of the air quality impacts on California associated with the implementation of the LCFS; whether the use of the fuel in the State will affect progress towards achieving State or federal air quality standards, or result in any significant changes in toxic air contaminant emissions; and recommendations for mitigation measures to address any adverse air quality impacts identified;
(11) Identification of hurdles or barriers (e.g., permitting issues, infrastructure adequacy, research funds) and recommendations for addressing such hurdles or barriers;
(12) Significant economic issues; fuel adequacy, reliability, and supply issues; and environmental issues that have arisen; and
(13) The advisability of harmonizing with international, federal, regional, and state LCFS and lifecycle assessments.

The Panel provided comments and feedback for staff's consideration. Along with the staff's assessment, the report includes Panel findings and recommendations to the degree that there was general agreement on an issue. These points of agreement were specifically noted in the report to differentiate them from the staff's sole assessments. In order to ensure that the range of viewpoints on any particular subject were adequately represented, ARB staff provided panelists with several opportunities to provide edits and feedback on all documents for which comments were solicited. As noted, however, staff was the final arbiter of content.

The regulation required ARB staff to evaluate the above topics and to solicit the Panel to participate in the review by commenting on the staff evaluations. Based on discussions with the Panel during the first meeting, staff added two additional topics, HCICO and credit trading, to the list of 13 that were required to be included in this review.

Though there were 15 topics covered under the 2011 program review, there are several workgroups predating the Panel that helped to inform the Panel by providing data, technical details, and recommendations during the review process. These workgroups[16] included:

- High Carbon Intensity Crude Oil Workgroup;
- Sustainability Workgroup;
- Biorefinery Siting Workgroup;

[16] See http://www.arb.ca.gov/fuels/lcfs/workgroups/workgroups.htm.

- LCFS Reporting Tool Workgroup;
- LCFS LUC Expert Workgroup; and
- LCFS Electricity Workgroup.

To the extent feasible, the work products from these and other LCFS workgroups have been incorporated into the review report that was considered by the Panel.

At its kick-off meeting, the Panel discussed its charge and overall priorities. This discussion was used to further focus the Panel's work. The Panels charter is posted on ARB's webpage[17].

E. Report Structure

As noted, the regulation calls out various areas for program review, many of which overlap in some way. Because of this overlap, the report has been structured to group similar and related topics together. In some cases, where a topic calls out several different broad ideas, those have been split and addressed separately in the appropriate sections of the report. Each chapter begins with a description of the topics that are addressed in the chapter, reciting the regulatory text for a clearer understanding of what can be found in each chapter.

As appropriate, each chapter provides a review of ARB staff's original work from the 2009 rulemaking. The review includes both the conclusions that staff reached for a particular subject matter and the rationale behind those conclusions. The chapter then discusses how the panelists and staff proceeded to review the topic, identifies new conclusions that can be drawn from the work of staff and panelists, and notes recommendations from the staff and panelists for moving forward. In many cases, the 2011 program review occurred so early in the LCFS program that there are not enough empirical data to properly assess the topic. In these cases, staff and panelists have worked together to qualitatively assess the progress to the extent feasible and then discussed what further steps would be taken for later reviews in order to assess further the progress of the program. It has become evident that ongoing monitoring and periodic updates to the Board on the status of the program is necessary.

F. Advisory Panel Structure

1. Overall Structure

Mr. Richard Corey, Chief of the Stationary Source Division, Air Resources Board, served as Chair of the Panel, with Dr. Michelle Buffington acting as Co-Chair. A professional facilitator was brought in to run the meetings. With input from the Chair, the facilitator helped prepare meeting agendas, prepare minutes, and assist with report preparation. In addition to the panelists, outside experts were invited to particular meetings to provide information that may be useful to the Panel in developing its comments.

[17] http://www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/charter011411mwb-v.1.pdf

Staff established a model for releasing information to the Panel as follows:

- Draft outlines were generally distributed at least one week prior to a Panel meeting.
- During the meeting, panelists had open periods of time where they could discuss additions or modifications to the outline. In some cases, panelists offered their own expertise to help support or refute details contained in the outlines. In addition to comment periods built into the meetings, staff also provided a public comment website where both panelists and the public could submit written comments.
- Depending on the degree of panelist participation, some topics warranted an additional sub-workgroup to be formed. Some of these workgroups were led by ARB staff (e.g., economics workgroup, credit trading workgroup). On the other hand, some panelists formed their own workgroups, which then provided reports back to the Panel. Such reports then helped to inform various chapters of the staff report (e.g., the independent work on investments, advisability of including a flexible compliance alternative).
- From these outlines and panelists' work products, draft chapters were written and presented to the Panel.
- Panelists were given time to comment both during the meeting (if the chapter was presented during a meeting) and through the public comment website.
- These draft chapters were then included in the draft report that was distributed the week of the Panel's October meeting. Panelist and public comments on the draft were used to help finalize this report which will be discussed at the December 2011 Board hearing.

2. Panel Meetings

All panel meetings were public and complied with the requirements of the Bagley-Keene Open Meeting Act of 2004 and related rules, regulations, and policies.[18] The Panel met six times in an effort to review staff's analyses and develop its recommendations for consideration by the Board. Several of these meetings were two days long, as requested by panelists during the first meeting. Panel members and the public could attend the meetings both via telephone and webinar. Meeting materials (e.g., meeting agendas, meeting summaries, presentations, documents to be reviewed) were posted on ARB's web site in a timely fashion, which provided Panel members and the general public with ample time to review the documents prior to the meetings. The meetings focused on high-level discussions regarding staff's analyses/assessments of specific topics called out in the regulation, as well as the work that other panelists were contributing for the report.

G. Summary

This Panel provided input in the form of expert opinions, data, white papers, and presentations for staff to complete the 2011 review of the LCFS regulation. With this

[18] See "A Handy Guide to The Bagley-Keene Open Meeting Act 2004," which is available at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/hg_ca_open_meetings_act.pdf.

information and information that staff gathered, staff prepared a report that covers details of how the panelists and staff proceeded to review the topic, new conclusions that can be drawn from the work of staff and panelists, and recommendations from the staff and panelists for moving forward. In those cases where there was insufficient information to make quantitative conclusions about the program (due to its infancy), staff and panelists have worked together to qualitatively assess the progress to date. We then collaborated on a discussion of further steps that could be taken to assess the progress of the program in a later review.

While specific information about future availability of low carbon fuels was unable to clearly prove the ability of regulated parties to comply in the future, some panelists raised concerns about the availability of low carbon intensity transportation fuels – both in terms of timing and volumes while others asserted that the program is beginning to send the signal to biofuel producers to make the investments so that next generation low CI fuels are available. Since the next Periodic Review is not required until 2014, it has become apparent that continual monitoring of key components of the program is necessary to help ensure the program's success.

III. Advisability of Harmonization

A. Introduction

Harmonizing LCFS programs means bringing key elements of different LCFS regulatory frameworks into accord with one another, while recognizing that these elements will not necessarily be (or need to be) identical. For example, it is important for LCFS programs to consider the carbon intensity (CI) of alternative fuels, rather than simply consider alternative fuel volume requirements. The carbon intensities of fuels in LCFS programs may differ due to regional variations in the energy required for feedstock production, the feedstocks used for electricity production, and the transportation distances of feedstocks and fuels used for estimating CI. However, the inclusion of CIs in all LCFS programs will encourage the production of lower CI fuels.

Harmonizing fuel programs between state, federal, and foreign jurisdictions is useful to ensure the optimum reduction of greenhouse gas (GHG) emissions. Similar fuel program frameworks reduce the possibility of fuel shuffling across different jurisdictions and they reduce the administrative burden for both regulated parties and regulatory agencies. Program elements that should be considered for harmonization include lifecycle analysis (LCA), sustainability requirements, reporting requirements, and credit calculations. For LCA, the specific model used for calculation (CA-GREET, GHGenius, etc.) is not important as long as all facets of fuel production (feedstock production, feedstock transportation, fuel production, fuel transportation and storage, and land use change) and fuel use are similarly considered. The harmonization of LCFS programs is not without risks. Harmonization must not be achieved at the expense of actual GHG emissions or environmental considerations. For example, harmonizing the California LCFS with programs that do not fully consider land use change could make it difficult to achieve real GHG emissions on a global scale.

B. Harmonization of California LCFS with Other Programs

A number of California legislative and policy directives support the California LCFS. The State legislature and various State agencies have approved a number of measures that promote the use of renewable fuels, mandate reductions in GHG emissions, and encourage the use of non-petroleum-based fuels.

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, among other provisions, increasing volumes of biofuels every year, up to a required volume of 36 billion gallons by 2022. 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-CI biofuels that could be used toward compliance with California's LCFS. In addition, successful implementation of RFS2 would signal that the necessary technological breakthroughs to produce second and third generation biofuels have occurred. As ARB developed the LCFS regulation, staff worked with U.S.EPA in an effort to harmonize the respective fuel programs in a number of critical areas, such as the inclusion of indirect impacts associated with land use changes. However, full harmonization was not possible due to constraints placed on RFS2 in the enabling legislation.

ARB has also been coordinating with representatives from Oregon, Washington, Northeast States for Coordinated Air Use Management (NESCAUM: a regional organization of eight northeastern states), British Columbia, and the European Commission. ARB staff coordination with representatives of other government agencies will continue because the LCFS will deliver greatest benefits if it is adopted in a consistent manner by multiple jurisdictions. Although other program frameworks are not the same as the California LCFS, there is a great deal of interaction and cooperation amongst representatives from the different agencies. Many of these other jurisdictions have begun working toward similar provisions to the LCFS.

C. Background on Other State, Province, and Regional Programs

Several LCFS programs are under development or in consideration in other regions within U.S. and Canada. This section briefly describes these programs and their current status.

1. Northeast/Mid-Atlantic Regional Clean Fuels Standard Update

Eleven northeast and mid-Atlantic states[19] are currently participating in the evaluation of a regional Clean Fuels Standard (CFS), which would lower the average carbon intensity of transportation fuels in the region and support the development and use of alternative fuels such as advanced biofuels, electricity, and natural gas. A 2009 Memorandum of Understanding signed by the Governors of the eleven states committed the states to developing a program framework and conducting an economic analysis of the potential impacts of the program.

NESCAUM[20] is providing technical and policy support to the state governments in this effort and conducted the economic analysis on behalf of the states. NESCAUM completed its analysis and published a report detailing the results in August 2011. Among the key findings of the report were that the program could provide small but positive economic benefits while reducing greenhouse gas emissions and dependence on imported petroleum fuels.

The states have maintained an active stakeholder process, and are currently in a public comment period during which interested parties may provide feedback on the results of the economic analysis. Additionally, the states and NESCAUM held two public stakeholder meetings—in Boston on September 20, 2011 and in Baltimore on September 22, 2011—to discuss the findings of the analysis and solicit input from stakeholders and interested parties.

[19] The eleven states are Connecticut, Delaware, New Hampshire, New Jersey, New York, Maine, Maryland, Massachusetts, Pennsylvania, Rhode Island, and Vermont.
[20] The economic analysis report and other materials related to the evaluation of a Clean Fuels Standard can be found on the NESCAUM website: http://www.nescaum.org/topics/clean-fuels-standard/

The states and NESCAUM are continuing to develop a potential framework for the program, addressing issues such as identification of regulated parties, treatment of fuels derived from high-carbon sources, indirect land use change, and others. NESCAUM is also closely following other governments (including California) efforts to develop or analyze fuel carbon intensity standards. The states have not made any final program decisions at this time, and are continuing to evaluate framework options based on input from stakeholders and the best available science.

2. Oregon

An LCFS program was authorized by the Oregon Legislature in 2009 as part of House Bill 2186. The Department of Environmental Quality (DEQ) was tasked with designing the program. The DEQ convened a 29-member advisory committee, reflecting a broad range of stakeholders that are potentially regulated or affected by the program, to discuss various aspects of program design. The DEQ released in January 2011 draft rules reflecting the recommendations of the advisory committee. The proposal is modeled after California LCFS while being customized to meet conditions in Oregon. The proposal mandates a 10 percent GHG reduction that is to be achieved by 2022. The Oregon LCFS program does not cover propane, which was specifically excluded from HB 2186. The program also exempts farm and logging trucks. There are several safeguards to protect low carbon fuel producers, regulated parties, and consumers from unintended negative effects of low carbon fuel standards, such as an inadequate supply of low carbon fuels or a non-competitive price of fuel with its neighbors. Such safeguards include a series of exemptions, deferrals, and periodic program reviews. Although the methodological approaches of the Oregon LCFS have not been finalized, they appear similar to the California LCFS. However the Oregon LCFS does not include LUC. The Oregon DEQ is currently reaching out to key stakeholders and working with other governments that are implementing or studying similar programs to work through common issues. Staffing and revenue considerations are being analyzed given changes in agency funding.

3. Washington

Executive Order 09-05 directs the Washington Department of Ecology to assess LCFS provisions that would best help the state meet its GHG goals. The final GHG plan developed in 2010 noted “a number of questions that we will continue to assess before making a recommendation to the Governor on whether or not we believe Washington should implement [an LCFS program].” The final report on LCFS was published in February 2011. The plan assumes carbon intensity will be reduced 10 percent from 2007 levels by 2023, with reductions beginning in 2014. The Department of Ecology has begun their yearly monitoring of GHG emissions in the state.

4. British Columbia

British Columbia (BC) currently has an LCFS program that applies to transportation fuels manufactured, brought into, or received in BC. The GHG reduction targets are same as California LCFS program, i.e. a 10 percent reduction in carbon intensity by

2020, the BC program includes propane as a regulated fuel. LCFS credits are not restricted from use in other programs; however, credits generated outside the LCFS program cannot be used for compliance. Although there are similarities with the California LCFS, there are also some important differences. In contrast to the California LCFS, the BC program does not, at this time, include indirect land use change (ILUC). The model used for estimating the direct CI is GHGenius, similar in principle to CA-GREET model. BC is participating in federal development of sustainability criteria in Canada.

5. Midwestern Governor's Association

The Midwestern Governor's Association represents Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Ohio, South Dakota, and Wisconsin. The Advanced Transportation Fuels Advisory Group is currently undertaking studies and discussions of a Low Carbon Fuels Policy. The preferred approach presented in the 2010 Low Carbon Fuels Policy Advisory Group Recommendations[21] is to proceed with a national LCFS. However, given the uncertainty surrounding that possible the next best option proposed was to proceed with a coordinated regional LCFS with 2005 as baseline for reductions and to require 10 percent reductions within 10 years of implementation. LUC is not recommended in the document pending further study.

D. Background on National Programs

1. RFS2

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 petroleum fuel suppliers to use a progressively increasing amount of biofuel, culminating in at least 36 billion gallons of biofuel by 2022 (see Table III-1). RFS2 differentiates between "conventional biofuel" (corn-based ethanol), “cellulosic biofuel”, “biomass-based diesel”, and "advanced biofuel." Advanced biofuel is renewable fuel, other than corn starch-based ethanol, with lifecycle GHG emissions that are at least 50 percent less than GHG emissions produced by gasoline or diesel. 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.

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 that 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

[21] (http://www.midwesterngovernors.org/Publications/LCFPagDoc.pdf)

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. In 2010 and 2011, U.S. EPA made changes to the RFS2 program as required by the EISA. The revised volumetric requirements established new specific annual volume standards for cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel that must be used in transportation fuel. The following charts show the volumetric requirements of the EISA (Table III-1) and the revised standards for 2010 and 2011 (Table III-2).

Table III-1: EISA Renewable Fuel Volume Requirements (billion gallons)

Year	Cellulosic biofuel requirement	Biomass-based diesel requirement	Total Advanced biofuel requirement (Includes Cellulosic and Biomass-based diesel)	Total renewable fuel requirement (Includes all other renewable fuels)
2008	n/a	n/a	n/a	9.0
2009	n/a	0.5	0.6	11.1
2010	0.1	0.65	0.95	12.95
2011	0.25	0.80	1.35	13.95
2012	0.5	1.0	2.0	15.2
2013	1.0	a	2.75	16.55
2014	1.75	a	3.75	18.15
2015	3.0	a	5.5	20.5
2016	4.25	a	7.25	22.25
2017	5.5	a	9.0	24.0
2018	7.0	a	11.0	26.0
2019	8.5	a	13.0	28.0
2020	10.5	a	15.0	30.0
2021	13.5	a	18.0	33.0
2022	16.0	a	21.0	36.0
2023+	b	b	b	b

a To be determined by EPA through a future rulemaking, but no less than 1.0 billion gallons.
b To be determined by EPA through a future rulemaking.

Table III-2: Revised Standards for 2010 and 2011

Fuel Category	**Percentage of Fuel Required to be Renewable**		**Volume of Renewable Fuel (in billion gal)**	
	2010	**2011**	**2010**	**2011**
Cellulosic biofuel	0.004%	0.003%	0.0065	0.0066
Biomass Based Diesel	1.10*	0.69%	1.15*	0.80
Total Advanced biofuel	0.61%	0.78%	0.95	1.35
Total Renewable fuel	8.25%	8.01%	12.95	13.95

**Combined 2009/2010 Biomass-Based Diesel Volumes Applied in 2010*

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 percent of the GHG benefits of the proposed regulation, and does not incent fuels such as natural gas, electricity, or hydrogen. California's LCFS complements the federal RFS2.

2. Consideration of a National LCFS

A national LCFS policy is desirable to bridge across the portfolio of state and regional LCFS policy initiatives under development. Such a policy would aim to provide comprehensive and consistent incentives across the nation for greenhouse gas emissions reductions from transportation fuels, offering potential policy benefits for the environment, fuel consumers, regulators, and regulated parties. A National LCFS Study project was created in January 2009 to respond to key information gaps regarding a potential national LCFS. This study is a collaboration between researchers from six research institutions, including Institute of Transportation Studies; University of California, Davis; Department of Agricultural and Consumer Economics/Energy Biosciences Institute; University of Illinois, Urbana-Champaign; Margaret Chase Smith Policy Center and School of Economics; University of Maine; Environmental Sciences Division, Oak Ridge National Laboratory; Green Design Institute of Carnegie Mellon University; and the International Food Policy Research Institute.

Consistent with the California LCFS, the National LCFS Study envisions a policy would respond to specific, documented market failures and barriers that, taken together, are expected to continue limiting the effectiveness and economic efficiency of advancing transportation sector mitigation with economy-wide climate policy instruments, such as carbon taxes and cap-and-trade schemes. Within this context, the primary objectives of the national LCFS project are to:

- Compare LCFS with other policies for reducing anthropogenic GHG emissions from transportation; and
- Develop policy design recommendations for a national LCFS policy that would be effective, implementable, and compatible with a broader portfolio of climate policies.

Policy design recommendations are intended to define at a high level a national LCFS policy framework that would be effective, implementable, broadly compatible with state and regional initiatives underway, complementary to a broader portfolio of national and international climate policies, and acceptable to the majority of the stakeholders. It also aims to harmonize state-implemented LCFSs and reduce potential conflicts or even counterproductive policy measures. Policy design recommendations will cover issues related to program coverage and scope, baseline and targets, fuels and vehicle characteristics, fuel pooling, measuring lifecycle carbon intensity (including spatial boundary, land use change, uncertainty), default and opt-in reporting, point of regulations, chain of custody, market mechanisms, compliance, penalties and cost containment, sustainability safeguards, and interactions with other policies.

E. Background on Other Countries' Programs

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. However, suppliers will be required to 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. The required reduction in GHG emissions is to be accomplished through the use of biofuels, alternative fuels, and reductions in flaring and venting. The fuel directive 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.

Sustainability requirements are also included in the European Fuel Quality Directive. For example, biofuels are prohibited from being made from raw material obtained from land with biodiversity value; biofuels cannot be from made from raw material obtained from land in several categories defined as having 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. Member States require economic operators to show that the 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 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. Furthermore, Member States 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.

The Fuel Quality Directive provides the potential outline for a program very similar in its characteristics to the Low Carbon Fuel Standard. While staff notes that to date European Member States have not implemented LCFS-like carbon performance based programs to meet the FQD target, this is an area where there may be considerable potential for knowledge transfer and harmonization in future.

F. Priority Areas for Possible Harmonization

1. Lifecycle Assessment

The LCFS regulatory framework builds upon estimates of the CI of each regulated fuel pathway. CI is determined using LCA of the aggregate quantity of GHG emissions associated with the production, transport, storage, and use of a fuel, including the "direct" effects and "indirect" effects. As the name implies, direct effects (or attributional emissions) are those that are directly connected with the production and use of a fuel, such as the growing and harvesting of the feedstock, the transport of the feedstock to the biorefinery, the emissions from the biorefinery, the transport of the fuel from the biorefinery, and vehicle tailpipe emissions. Indirect effects (or consequential emissions) are generated by secondary processes (usually by supply/demand dynamics of fuel feedstocks) set in motion by a fuel production process.

Several models are currently in use to perform LCA of fuels. For example, the California LCFS program uses CA-GREET (California version of the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model) to determine direct effects and GTAP (Global Trade Analysis Project model) to determine indirect effects due to land use change. The RFS2 and European programs use FAPRI/FASOM (Food and Agricultural Policy Research Institute/Forest and Agricultural Sector Optimization Models) and RED/FQD (Renewable Energy Directive/ Fuel Quality Directive) methodologies, respectively, for the LCA under those programs. While the individual models being used by different jurisdictions may differ in some respects, the emphasis for a harmonization effort should be to strive for consistency in the data and on the assumptions used in conjunction with these models so that the overall results can be meaningfully compared.

Harmonization of LCA methodologies between jurisdictions could lead to more consistent prices for low carbon fuels and reduce the potential fuel shuffling. For example, suppose a biofuel production facility is assigned different CI values under different LCFS programs or one LCFS program includes ILUC estimates in lifecycle analyses and another LCFS program does not. Inconsistencies in CIs will create incentives to move fuels between states to maximize the credit received under the inconsistent programs. It is important to note that the actual direct CI values for the individual fuel pathways are not expected to be identical but are expected to vary between different jurisdictions. The variations occur not so much due to the assessment methodology but rather due to local influences on the inputs to the fuel production chain (e.g. type of energy use in the refinery, local transportation inputs for the feedstocks and products, etc.). However, as long as the GHG accounting methodologies are fundamentally similar and are using similar assumptions for data inputs, the potential for leakage and shuffling could be minimized.

An important benefit provided by the harmonization of LCA under similar programs is the reduced need to undertake new analyses for every region. Other jurisdictions can use the LCA values or inputs for fuels approved under Method 2A/2B of the California LCFS program, with specific modifications to reflect regional effects where needed. A set of best LCA practices once established in a jurisdiction can serve as a learning experience for others without the need to replicate the efforts, thus reducing the burden for all programs.

2. *Fossil Fuel/HCICO Treatment*

The California LCFS includes a provision for addressing high carbon intensity oil (HCICO). The inclusion of HCICOs in the California LCFS regulation recognizes that production of some crude oils requires additional energy to (e.g., bitumen mining or thermally enhanced oil recovery techniques) or results in higher levels of GHG emissions during the production process (e.g., excessive flaring). The California LCFS full lifecycle assessment accounts for some emissions from these effects, but does not reflect a widespread shift to higher carbon intensity crudes. If the 10 percent emission intensity reduction goal of the LCFS is to be maintained, the additional GHG emissions should be taken into account if California refineries process these crudes in larger amounts than currently accounted for. An important goal of the HCICO provision is to provide a signal for oil producers to engage in upstream emission reduction activities, such as reducing flaring, improving energy efficiency, and using carbon capture and sequestration.

Other jurisdictions generally do not address the HCICO issue, although the European Commission recently voted to treat Canadian oil sands uniquely[22]. Harmonization of the treatment of HCICO across jurisdictions will boost the signal to crude oil producing companies for GHG emission reduction activities and promote innovation. An important additional benefit of harmonization in this area is a reduction in carbon leakage due to shuffling. A harmonization effort will require the development of consistent a methodology to determine carbon intensity of crude oil production from various processes and sources around the world. ARB staff is currently working on a tool that standardizes this methodology, while a concurrent effort is underway in Europe. Once developed, this tool will be used to assess variations of crude production emissions on a periodic basis. This tool will be made available for use by other jurisdictions as well.

3. *Sustainability*

Harmonized sustainability criteria could reduce the burden on businesses. The Board directed staff in Resolution 09-31 to work with appropriate state and federal agencies, environmental advocates, regulated parties, and other interested stakeholders to develop sustainability provisions to be used in implementing the LCFS regulation. ARB staff has been working with these stakeholders, as well as with national and international partners to address potential sustainability issues arising from the worldwide demand of biofuels.

Staff is assessing how existing laws and regulations address sustainability for the management and harvest of biofuel feedstocks and biofuel operations. Also, because several other countries have initiatives that are farther along than the LCFS, staff is following the development of certification and benchmark systems developed by other countries, organizations, or industry groups that can serve as models for California. We

[22] http://www.euractiv.com/climate-environment/eu-faces-tar-sands-industry-news-508140

will continue to work with these entities to ensure our process is in harmony with theirs, to the extent feasible.

For more information about the workgroup and their progress, please see the environmental chapter of this report.

4. Reporting and Chain of Custody

Harmonized chain of custody and reporting requirements could reduce the burden on businesses operating in several jurisdictions. Under the California LCFS program, staff has worked with stakeholders to establish procedures for reporting information under the program. An integral part of this effort has been the development of a web-based reporting tool for fuel producers to use to establish compliance under the program. Regulated parties use the LCFS Reporting Tool (LRT) to electronically manage accounts, enter or import fuel data, submit electronic reports and corrections, and track credits and deficits. Additionally, ARB staff has established a voluntary Biofuel Producer Registration program to help facilitate biofuel transactions by giving buyers and sellers of biofuels a common online resource containing registered CI values and physical pathway information that can be traced to specific production facilities. In turn, the information helps regulated parties to use registration data for LCFS reporting and compliance purposes. The reporting and tracking tools developed under the California LCFS program can be made available to other states' programs, thus reducing the need to reinvent the wheel. Aligning the reporting requirements across jurisdictions and nationally would serve to reduce the administrative burden for the regulated parties that have to report to both federal and state programs; however, the fundamental structure of the different state and federal programs may not always make it feasible to have identical reporting structures. For example, the reporting requirements under the RFS2 and California LCFS are not the same due to programmatic differences.

5. Credit Market

A credit market that allows import/export of credits between LCFS programs will potentially enhance the compliance flexibility provided under the individual programs. The LCFS credits, denominated in metric tons of carbon dioxide equivalent ($MTCO_2e$), are based on an analysis of the transportation fuel's full lifecycle carbon intensity.
A key consideration for the success of an expanded credit market is to ensure equity in credits between separate programs. Equivalence may be achieved by harmonization of the other elements of the program such as LCA methodologies, treatment of crude oil, compliance schedules, etc.

G. Summary

The harmonization of LCFS programs is important for ensuring that global GHG emission reductions actually result from these programs. Harmonizing LCFS programs to the extent practical will help to create an environment where credits may be freely traded, fuel shuffling will be inhibited, and the burden on regulated parties and regulatory agencies will be lessened. ARB will continue to work with representatives from other government LCFS programs in an effort to harmonize LCA methods, sustainability requirements, reporting requirements, and credit trading mechanisms.

IV. Advances in Lifecycle Assessment

A. Introduction

There are two main components to the fuel-lifecycle assessment: direct and indirect effects, the former primarily encompassed in the Method 2 process and the latter addressed through the continued development and review of land use change values and other indirect effects, informed in part by the Expert Workgroup. These activities are a key element of the LCFS regulation, as they inform the carbon intensity for each fuel pathway, which in turn translates into the credits or deficits under the program as a function of volumes introduced into the transportation system. The advisory panel met once to discuss lifecycle analysis, and the discussion centered around the details of how the calculation is done. There was very little discussion about whether the regulation should change the model or other key inputs to the assessment.

When the Board approved the LCFS in April of 2009, it approved two fuel pathway Lookup Tables containing a total of 64 staff-developed pathways. Of those pathways, 37 were for gasoline (CARBOB) and gasoline substitutes, and 27 were for diesel and diesel substitutes. The carbon intensities (CIs) associated with those pathways were estimated using one or both of two models: version 1.8b of CA GREET and the GTAP model[23]. CA-GREET was used to estimate the direct fuel life cycle emissions, while GTAP was used to estimate the emissions associated with indirect land use change (LUC). Although the direct well-to-wheels emissions associated with all of the original 64 pathways were estimated using CA-GREET, not all of those pathways were associated with identifiable LUC emissions. Thus, GTAP was used on only a subset of pathways: corn ethanol, sugarcane ethanol, soy biodiesel, and soy renewable diesel.

Since the Board approved the LCFS in April 2009, there have been few changes in the CA-GREET model used for estimating direct emissions of fuel pathways, but significant technical activity related to the GTAP model used to estimate indirect emissions. Both of these models are discussed below, including what impacts advances or changes in lifecycle analysis may have on the LCFS regulation.

B. Direct Effects

1. Background

In order to make the fuel pathway approval process as transparent as possible, the Lookup Tables containing the original set of 64 pathways were included in the LCFS regulation. As a result, adding new or modified pathways to the table could only be accomplished through the full regulatory change process: the publication of an Initial Statement of Reasons, a 45-day public comment period, a public hearing before the Board or the Executive Officer, the publication of a Final Statement of Reasons in which all comments submitted receive response, and final approval by the Office of

[23] The GREET was originally developed by Argonne National Laboratories and later modified for the development of California-specific fuel pathways by TIAX Associates and Life Cycle Associates. The GTAP was developed by Thomas Hertel and others at Purdue University.

Administrative Law. Foreseeing a time when the evaluation and approval of proposed new pathways becomes well-defined, standardized, and accepted by the regulated community, the Board directed staff in Resolution 09-31 to explore the feasibility of converting the pathway approval process to a certification program. This conversion would expedite and streamline the approval process. Staff is currently developing the requested Method 2 pathway certification program. Additional details on the proposed program are presented below.

New and modified pathways are developed in two ways under the LCFS. They can be developed by ARB staff, as was done with the original set of 64 pathways, and by fuel providers. Fuel providers apply for new pathways under the Method 2 provisions of the LCFS regulation. Method 2 is subdivided into Method 2A, for pathways that are modified versions of existing Lookup Table pathways, and Method 2B, for fuels or production processes without close analogs in the Lookup Tables. Both categories of pathways—staff-developed and Method 2 pathways—are subject to the same regulatory change approval process.

2. Pathway Development

Responding to concerns from Method 2 pathway applicants that the pathway approval process would delay the introduction of new low-CI fuels into the California market, the Board directed Staff in Resolution 10-49 to develop a process whereby applicants could begin using their pathway CIs on a temporary basis once staff recommends those CIs for approval.

The process staff developed is contained in Regulatory Advisory 10-04. This Advisory allows Method 2 pathway applicants to begin using their proposed pathway CIs as soon as they are recommended for approval by ARB staff and posted to the Method 2 web site. If pathways posted to the Method 2 web site are eventually modified or denied at hearing, the applicant may continue using the posted CIs for up to six months following the hearing decision.

Beginning in early 2010, fuel producers began submitting fuel pathway applications under the Method 2 provisions of the regulation. At the same time, staff began working on yet another directive from Resolution 09-31: developing a new set of priority fuel pathways that could be appended to the Lookup Tables and then used by fuel producers. To date, 106 producer-developed pathways and six staff-developed priority pathways have been posted to the Method 2A/2B web site. The Method 2A and 2B pathways that have been posted are summarized in Table IV-1.

Table IV-1: A Summary of the Methods 2A and 2B Pathway Applications Recommended for Approval[a] and Posted as of 9/16/2011

Feedstock and Fuel	Number of Applications[b]	Number of Pathways
Corn Ethanol	14	46
Corn-Sorghum Ethanol	5	43
Beverage waste	1	1
CBI Cane ethanol	5	15
Natural gas	1	1
Total	26	106

[a] 106 pathways do not include the 64 pathways in the original regulation.
[b] Individual applications can contain multiple individual pathways. Multiple pathways allow the applicant to account for variable production parameters such varying amounts of biogas in the thermal energy stream or varying co-product characteristics.

Whereas none of the producer-developed pathways appearing on the Method 2A/2B web site are for diesel substitute fuels, four of the six posted ARB-developed pathways are for diesel substitutes (see Table IV-2).

Table IV-2: ARB Priority Pathways Recommended for Approval and Posted as of 9/16/2011

Feedstock and Fuel	Number of Pathways
Midwestern used cooking oil to California biodiesel	2
North American canola to California biodiesel	1
Midwestern corn oil to California biodiesel	1
Midwestern sorghum to Midwestern ethanol	2

The pathways posted to the Method 2A/2B website are recommended for approval rather than approved. Regulatory Advisory 10-04 makes the posted pathway CIs available for use, pending final approval by the Executive Officer. To date, 25 of the posted producer-developed pathways and three of the ARB-developed pathways have been heard by the Executive Officer. Staff presented all 28 of these pathways at an Executive Officer public hearing on February 24, 2011. Due to public comments received on one of the pathways, as well as pathway changes requested by one of the applicants, the approval package was remanded to staff for revision. The requested changes have almost been completed. When they are, a 15-day public comment period will allow for additional input related to these specific revisions. Then staff will prepare a Final Statement of Reasons and submit it to the Office of Administrative Law. Staff expects these pathways to be adopted and added to the LCFS Lookup Table.

3. Current Method 2A/2B Applications

Fuel producers are continuing to file Method 2A and 2B applications, and ARB priority pathway development is ongoing. Among the Method 2 applications currently under consideration include corn ethanol, biodiesel, and waste-to-fuel applications. ARB staff is also developing an anaerobic digestion pathway which will utilize organic municipal solid waste as a feedstock.

4. Transition from a Regulatory to a Certification Process

LCFS staff is scheduled to submit a package of regulation changes to the Board for approval in December of 2011. Among the proposed changes is language that would remove the current pathway approval process from the regulation change framework and convert it to a certification program. Under this proposal, all Method 2A and 2B submission requirements and all the procedures and criteria used to evaluate applications—as well as ARB-developed pathways—would be spelled out in detail in the regulation. The proposed changes would obligate ARB staff and the Executive Officer to apply those criteria and procedures objectively and uniformly in all cases. The role of discretion in the approval process would be minimized.

The Lookup Tables will remain in the regulation. However, certified fuel pathways will be listed on ARB's web page and will be available for immediate use. Periodically, ARB staff will propose to the Board that the Lookup Tables be updated with the certified pathways. The transparency associated with the rulemaking process should be maintained. Therefore, staff proposes that applications would continue to be posted for public comment and would be subject to revision based on comments received.

5. Future of the Pathway Approval Process and of CA-GREET

Although CA-GREET is widely accepted and generally regarded as technically sound, it is very difficult to use. A near-term priority for ARB staff is to significantly improve the model's usability while retaining or enhancing its ability to calculate fuel life cycle carbon intensities based on the best available engineering data, and best practices in the area of LCA. ARB will pursue this goal through a contract with a respected consultant with extensive experience with CA-GREET in particular and lifecycle analysis in general. As of this writing, that contract is being finalized. The resulting improved version of CA-GREET will be used by ARB staff, but will also be made available for use by the LCFS regulated community.

The approach to the modification of the GREET model is consistent with the overall direction ARB envisions for the LCFS fuel pathway development function. ARB's experience to date has indicated that it makes more sense to concentrate pathway development efforts on adding new pathways to the Lookup Table than it does to update the pathways already there. Fuel providers who have products with CIs that are lower than the applicable CIs in the Lookup Table can apply for custom pathways through the Method 2A process. ARB staff can also target its pathway development efforts on important emerging fuels that have the potential to contribute significantly to the CI-reduction goals of the LCFS. In sum, ARB staff has seen that the pathway development opportunities currently in place provide fuel providers with ample opportunity to obtain pathway CIs that fairly and accurately reflect their actual production life cycles. As staff is able to transition the pathway approval process away from the resource-intensive regulatory change framework, the development and approval of new pathways will be able to accelerate.

Members of the Advisory Panel have asked whether the pathway development process will begin to incorporate mechanisms that recognize the adoption of sustainable agricultural practices that minimize GHG emissions. There is no question that the adoption of such practices is consistent with the goals of the LCFS. As such, ARB is considering mechanisms to credit such practices through its LCFS Sustainability Workgroup.

6. *Summary of Direct Emissions Lifecycle Analysis*

Although newer versions of GREET have been developed since the Board approved the LCFS, staff believes that Version 1.8b is more than adequate to estimate direct emissions from a fuel pathway. On the other hand, the platform on which GREET currently operates makes it difficult to use and manage. To address this issue, ARB is contracting with a consultant fluent with GREET to make modifications that will make the model more user-friendly.

Staff does not expect that the methodology for the estimation of direct emissions for fuel pathways to significantly change in the near future. Should the GREET model be modified to the extent that significant changes are introduced, or a better model is developed, staff will take these changes into consideration and recommend revisions to the fuel pathway CI values in the Lookup Tables as warranted. Should staff propose, and the Board approve, modifications to CI values in the Lookup Tables due to advances in lifecycle analysis, and those modifications impact the LCFS compliance schedule, the revised CI values would presumably take effect at the beginning of a new compliance period (i.e., January 1st) for ease of implementation.

C. *Lifecycle Assessment – Indirect Effects*

1. *Summary of "Original" Indirect Effects Modeling for the LCFS*

a. *Land Use Change (LUC) Modeling for Biofuels*

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 cropland both in the U.S. and in countries with agricultural trade relations with the U.S. In order to isolate the land use changes resulting specifically from an increase in biofuel production, one must determine the differences in land use between the "world with the increase in biofuel production" and the "world without the increase in biofuel production." Unfortunately, empirical data on land use is not available for at least one of these "worlds." Because of this limitation, a model is required to isolate the differences in land use resulting from a change in biofuel production.

i. Choice of model

Models used to estimate land use change impacts must be international in scope. The Global Trade Analysis Project (GTAP) model 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. A more comprehensive discussion of the models considered by ARB and the choice of the GTAP model is given in Appendix C2 of the LCFS staff report.[24]

ii. Model Structure, Inputs and Assumptions

GTAP is a computable general equilibrium (CGE) model. CGE models are designed to seek equilibrium. If a change is introduced—increased demand for crop-based fuels, for example—fuel crops, fuels themselves, and a number of related prices will all change. Prices that rise will stimulate higher production and reduced demand in other sectors. Prices that drop will have the opposite effect. A CGE model will seek that point at which demand is satisfied by supply throughout the modeled economy. Once a new economy-wide equilibrium is reached, the model reports all changes that occurred, as well as the net, economy-wide change.

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 elasticity values are used to estimate the extent which introduced changes alter the prior equilibrium. Listed below are a few important inputs and parameters that the GTAP uses to model the land use change impacts of increased biofuel production levels. The values presented are for the original LCFS modeling.

- Baseline year: Version 6 of the GTAP database employs the 2001 world economic database as the analytical baseline. 2001 is the most recent year for which a complete global land use database existed at the time of the original modeling.

- 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.

- Yield-price elasticity: This parameter determines how much the crop yield will increase in response to an increase in price for the crop relative to input costs. If the yield-price 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

[24] Air Resources Board, March 2009, Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume 2, Appendices.

to a price increase. In the original modeling, scenarios were run in which this elasticity value was varied from 0.2 to 0.4.

- Elasticity of crop yields with respect to area expansion (yield ratio or ETA): This parameter expresses the yields that will be realized from newly converted lands relative to yields on acreage previously devoted to that crop. The original modeling assumed that 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 would be lower than corresponding yields on existing crop lands. Scenarios were run with yield ratio ranging from 0.5 to 0.75. A single value was used for all newly converted lands globally.

- Elasticity of harvested acreage response (flexibility of crop switching): 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 (Constant Elasticity of Transformation or CET function): This elasticity expresses the extent to which expansion into forestland and pastureland occurs due to increased demand for agricultural land.

- 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. The GTAP model uses Armington trade elasticities, which assume a limited willingness to substitute foreign product for domestic or to change trading partners.

iii. 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 “lost sequestration capacity” per unit land area which results from the conversion of native vegetation to crops. The value of emissions may be significant for areas with rapidly growing forests.

In the original modeling, staff chose to use emission factor data from Searchinger et al.[25] These emission factors include carbon-stock data on a wide variety of terrestrial ecosystems that are weighted according to historic land conversion patterns. In

[25] Searchinger, T., R. Heimlich, R. Houghton, F. Dong, A. Elobeid, J. Fabiosa, S. Tokgoz, D. Hayes, T. Yu, 2008, Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land-Use Change, Science.

deriving the emission factors, ARB assumed that 100 percent of the above-ground living biomass and 25 percent of soil organic carbon (to one meter depth) is emitted over the assumed 30-year time accounting period. Emissions from decomposition of below-ground biomass (roots), deadwood, and litter were not included. Sequestration of carbon in harvested wood products and non-CO_2 emissions from land clearing by fire were also not included.

iv. Time Accounting

Calculating the carbon intensity for a crop-based biofuel (e.g. corn ethanol) requires that time-varying LUC 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) that releases greenhouse gases at a relatively constant rate over the years in which it is used. To compare emissions for the two fuels in the LCFS, we need to convert the time-varying LUC emissions for biofuels into an equivalent series of constant annual emissions. In the original modeling, staff chose to annualize LUC emissions over a 30-year time horizon. In other words, the LUC carbon intensity value was calculated by dividing the GHG emissions resulting from land conversion by the energy content of 30 years of fuel production. Other methods considered by ARB for time accounting are discussed in chapter four and appendix C of the LCFS staff report.[26]

b. Indirect Effects for Fuels Other than Biofuels

As part of the original rulemaking, ARB identified no other significant indirect 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 did not provide any quantitative analysis that demonstrates that these impacts are significant. ARB concluded that excluding the indirect effects from the carbon intensity values of other fuels, such as electricity and petroleum, does not have any significant effect on the overall global warming potential of these fuels and does not substantially affect the assessment of the strategies and pathways that are likely to be used to comply with the regulation. But exclusion of the indirect effects from the carbon intensity values of some biofuels would give a completely erroneous assessment of the global warming potential and would introduce substantial errors in the assessment of the strategies and pathways that would likely be used to comply with the regulation. The exclusions would delay the development of truly low-carbon fuels and jeopardize the achievement of a ten percent reduction in fuel carbon intensity by 2020.

[26] Air Resources Board, March 2009, Proposed Regulation to Implement the Low Carbon Fuel Standard, Volumes 1 and 2.

2. *Advances in Indirect Effects Modeling*

a. *Revisions to GTAP Model*

i. *July 2010 Report from Purdue University*

In April 2010, Purdue University researchers led by Professor Wally Tyner released an updated analysis of land use changes associated with corn ethanol, which was requested and partially funded by Argonne National Laboratories. The analysis was subsequently revised in July 2010, at which time the model was made available.[27] GTAP model changes discussed in this report include:

- Addition of cropland pasture in the U.S. and Brazil and Conservation Reserve Program lands to the model and updating the land supply nesting structure.
- Revised energy sector demand and supply elasticity values.
- Improved treatment of production, consumption, and trade of DDGS.
- Revised structure of the livestock sector.
- Revised response of crop yields to price.
- Improved estimation of the productivity of marginal cropland.

ii. *Recent Model Changes*

In August 2011, Purdue researchers working with Argonne National Laboratory published a report titled "Global Land Use Changes due to the U.S. Cellulosic Biofuel Program Simulated with the GTAP Model."[28] In addition to many of the model changes listed above, this work focused on the introduction of advanced cellulosic biofuels into the GTAP modeling.

In September 2011, Professor Tyner submitted an interim report describing preliminary results and sensitivity analyses associated with short-term model revisions performed for ARB.[29] In addition to the model changes listed above for the July 2010 report, these short-term model changes included:

- Introducing biofuels into the 2004 version 7 GTAP data base.
- Improving treatment of soy oil, soy meal, and soy biodiesel.
- Adding greater flexibility in acreage switching among different crops in response to price changes.
- Including an endogenous yield adjustment for cropland pasture in response to changes in cropland pasture rent.

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[27] Tyner, W., F. Taheripour, Q. Zhuang, D. Birur, and U. Baldos, July 2010: *Land Use Changes and Consequent CO2 Emissions due to US Corn Ethanol Production: A Comprehensive Analysis*, Revised Final Report, Department of Agricultural Economics, Purdue University.
[28] Taheripour, F., W. Tyner, and M. Wang, August 2011: *Global Land Use Changes due to the U.S. Cellulosic Biofuel Program Simulated with the GTAP Model*, Final Version, Purdue University and Argonne National Laboratory.
[29] Tyner, W., September 2011: *Calculation of Indirect Land Use Change (ILUC) Values for Low Carbon Fuel Standard (LCFS) Fuel Pathways*, Interim Report posted online at http://www.arb.ca.gov/fuels/lcfs/09142011_iluc_wtreport.pdf .

b. LCFS Expert Workgroup

i. Background

In Resolution 09-31, the Board directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The Expert Workgroup was tasked with evaluating key factors that might impact the land use values for biofuels including agricultural yield improvements, co-product credits, land emission factors, food price elasticity, and other relevant factors. The Executive Officer has coordinated this effort with similar efforts by the U.S. EPA, European Union, and other agencies pursuing an LCFS.

Formation of the Expert Workgroup: Staff initiated efforts to convene the LCFS Expert Workgroup in August 2009. Staff shared with stakeholders and discussed during a workshop in August 2009 a preliminary proposal for the workgroup. This proposal contained staff's recommendations for the structure of the workgroup, the proposed member criteria and selection process, and potential topics for discussion. Subsequent member recruitment efforts took into consideration stakeholder feedback on the preliminary proposal.

The Expert Workgroup was established in February 2010. The workgroup was comprised of 30 members, including eight representatives of other agencies involved in LCFS-type activities. Technical expertise to tackle major issues of concern was a key consideration in our selection of members. The membership list can be accessed at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/ewg-members-list.pdf.

Expert Workgroup Meetings: The first meeting of the Expert Workgroup was held on February 26, 2010, and seven additional meetings were held at approximately monthly intervals through November 2010. The meetings were open to the public and broadcast electronically via either webcast or webinar. Meeting minutes and documents presented or discussed at these meetings were posted for public availability at the Expert Workgroup website (http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm).

ii. Summary of Key Findings and Recommendations

In reports submitted to ARB, the subgroups were asked to summarize their recommendations in three categories: 1) near-term analysis, 2) short-term work/research, and 3) long-term work/research. ARB staff presented these documents for public comment as submitted by the subgroups and without edit. Although many of the topics presented in these documents were discussed at Expert Workgroup meetings, these documents are products of the subgroups and not of the Expert Workgroup as a whole. Moreover, please note that some of these documents were wholly or substantially written by only a few active members of the subgroups as indicated on the title pages of the documents. The reports can be accessed at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm.

3. *Present Status and Future Work on Indirect Effects Modeling*

a. LUC modeling

i. Contracts

ARB has several active and pending contracts involving various aspects of LUC modeling.

- Professor Wally Tyner at Purdue University is under contract to make short-term revisions to the GTAP model and provide revised LUC estimates for U.S. corn ethanol, U.S. soy biodiesel, and Brazilian sugarcane ethanol.
- Purdue University has also been granted a two-year contract to explore longer-term model changes and prepare LUC estimates for several new pathways.
- Professor Holly Gibbs at University of Wisconsin-Madison is under contract to develop a data base of spatially explicit carbon stock estimates for both forests and soil carbon. These carbon stock estimates are being used to develop revised land conversion emission factors. Professor Gibbs is also quantifying the types and amounts of land included and excluded from the GTAP land use data base and suggesting possible means to improve the selection of land types for cropland expansion within the GTAP model.
- Professor Michael O'Hare and Dr. Richard Plevin at UC Berkeley are in the final stages of a contract that includes the development of new, spatially explicit emission factors.

ii. Short-term Revisions to LUC CI Values

ARB staff conducted a review of recommendations from the Expert Workgroup subgroups and independent reviewers to determine which recommendations were appropriate and could be completed in a timely manner for this round of model revisions. Recommendations not included in this round of revisions may be addressed as part of longer-term model updates. For several issues, disagreement over the recommended course of action existed between Expert Workgroup members or between Expert Workgroup members and the independent experts. In these situations staff carefully weighed the evidence and consulted further input prior to deciding on a course of action. Both ARB staff and Purdue researchers received additional information and comments from stakeholders and subject matter experts after the completion of the Expert Workgroup process. Some of these recommendations are also included in the revised modeling. Specific model updates included in the revised modeling are:

- Use of the GTAP 7 database;
- Addition of cropland pasture in the U.S. and Brazil and updating the land supply nesting structure;
- Re-estimated energy sector demand and supply elasticity values;
- Improved treatment of biofuel by-products and modified structure of the livestock sector;
- Improved method of estimating the productivity of new cropland;

- Adopting a consistent model version and set of model inputs for all biofuel pathways;
- More comprehensive and spatially explicit set of emission factors;
- Revised yield response to price;
- Revised demand response to price;
- Increased flexibility of crop switching in response to price signals;
- Incorporation of an endogenous yield adjustment for cropland pasture.

Use of the GTAP 7 Database: The original LUC modeling used version 6 of the GTAP database which depicted the world economy in the year 2001. More recently, version 7 of the GTAP database, which depicts the world economy in the year 2004, has become available. Version 7 was first introduced by Purdue researchers in 2009; however, it wasn't until 2011 that GTAP version 7 received the necessary updates for land use data to be used for LUC modeling[30]. In order to take advantage of these data, which represent a more recent state of the world economy and therefore is considered an improvement over version 6, the global production, consumption, and trade of first generation biofuels were introduced into the database. The detailed steps used to construct the new database are described in Appendix A of the August 2011 report for Argonne National Laboratories.[31]

Addition of cropland pasture in the U.S. and Brazil and updating the land supply nesting structure: In 2010, Birur introduced two new land categories, cropland-pasture and unused cropland, into the supply of land in GTAP.[32] Cropland-pasture was added as a land category in both the U.S. and Brazil while unused cropland was added in the U.S. only. Cropland-pasture is defined by the USDA as: "Cropland used only for pasture generally is considered in the long-term crop rotation, as being tilled, planted in field crops, and then re-seeded to pasture at varying intervals. However, some cropland pasture is marginal for crop uses and may remain in pasture indefinitely. This category also includes land that was used for pasture before crops reach maturity and some land used for pasture that could have been cropped without additional improvement. Cropland pasture and permanent grassland pasture have not always been clearly distinguished in agricultural surveys."[33] Unused cropland is primarily land which has been retired into the U.S. Conservation Reserve Program (CRP). Both cropland-pasture and unused cropland are explicitly defined as components of cropland. However, since cropland-pasture is largely used as an input to the livestock industry, an industry was added to the model that uses cropland-pasture as an input and sells its output to the livestock industry. This linkage facilitates the transition of cropland-pasture from the livestock industry to crop production and vice versa. Unused

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[30] Avetisyan, M., Baldos, U., and Hertel, T. March 2011. "Development of the GTAP Version 7 Land Use Data Base." GTAP Research Memorandum No. 19. Department of Agricultural Economics, Purdue University.
[31] Taheripour, F., W. Tyner, and M. Wang, August 2011: *Global Land Use Changes due to the U.S. Cellulosic Biofuel Program Simulated with the GTAP Model*, Final Version, Purdue University and Argonne National Laboratory.
[32] Birur, D.K, 2010. "Global Impacts of Biofuels on Agriculture, Trade, and Environment: A Computable General Equilibrium Analysis," Ph.D. Dissertation, Purdue University.
[33] USDA website http://www.ers.usda.gov/data/majorlanduses/glossary.htm accessed on August 24, 2011.

cropland (CRP) mainly provides environmental benefits and is an input into the GTAP sector that provides these services.

Re-estimated energy sector demand and supply elasticity values: The energy sector demand and supply elasticity values were re-estimated and calibrated to the 2006 reality using the widely used GTAP-E model of energy and climate policy.[34] This investigation revealed that demand and supply specifications in the previous modeling were too high; elasticities of substitution between petroleum and other fuels were too high; consumer demand elasticity for petroleum products was too high for many countries; and supply response in the petroleum sector appeared too large. These revised parameter specifications are now included in the GTAP-BIO-ADV modeling for LUC.

Improved treatment of biofuel by-products and modified structure of the livestock sector: In recent years, substantial effort has been made to improve the treatment of production, consumption, and trade of biofuel byproducts.[35,36]

These improvements include:[37]

- Using a multi-level nesting structure for demand of feedstuffs in the livestock industry;
- Separation of soybean from other oilseeds;
- Separation of soybean oil from other vegetable oils and fats;
- Separation of soybean meal from other oilseed meals;
- Assigning elasticities of substitution to the different components of the demand for feed to replicate changes in the prices for DDGS and meals in the U.S. and European Union during the time period of 2001 to 2006. The assignment of elasticities includes an elasticity of substitution between energy and protein feedstuffs to account for the potential of DDGS to displace oilseed meals in some feed rations.[38]

Improved method of estimating the productivity of new cropland: The GTAP parameter ETA represents the ratio of the productivity of crops produced on newly

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[34] Beckman, J., T. Hertel, and W. Tyner, 2011: *Validating Energy Oriented CGE Models*, Energy Economics, 33, 799-806.
[35] Taheripour, F., T.W. Hertel, W.E. Tyner, J.F. Beckman, and D. K. Birur. 2010. “Biofuels and their By-Products: Global Economic and Environmental Implications.” *Biomass and Bioenergy 34,* pp.278-89.
[36] Taheripour, F., T. Hertel, and W. Tyner. 2009. “Implications of the Biofuels Boom for the Global Livestock Industry: A Computable General Equilibrium Analysis,” An earlier version used for the background paper for the 2009 *State of Food and Agriculture (SOFA) From the Food and Agriculture Organization of the UN (FAO), a revised version is also presented at2009 Applied and Agricultural Economics Association meeting in Milwaukee Wisconsin,* Center for Global Trade Analysis, Purdue University.
[37] Tyner, W., September 2011: *Calculation of Indirect Land Use Change (ILUC) Values for Low Carbon Fuel Standard (LCFS) Fuel Pathways*, Interim Report posted online at http://www.arb.ca.gov/fuels/lcfs/09142011_iluc_wtreport.pdf .
[38] Arora S., M. Wu, and M. Wang. 2008. “Updated of Distiller Grains Displacement Rations for Corn Ethanol Life-Cycle Analysis.” Center for Transportation Research, Energy System Division, Argonne National Laboratory.

converted forest or pasture land to the productivity of crops on existing cropland. In the original modeling ARB ran several scenarios with ETA ranging from 0.5 to 0.75. In their July 2010 report, Tyner et al. discusses use of the Terrestrial Ecosystem Model (TEM), a bio-process-based biogeochemistry model, to generate a set of regional ETAs at the AEZ level.[39] The process used to generate these ETA values is discussed in detail in Appendix A of that report.

Adopting a consistent model version and set of model inputs for all biofuel pathways: In the original modeling, the LUC value for each pathway was an average of multiple scenarios run with different input values for key parameters, such as yield-price elasticity and ETA. Unfortunately, there was inconsistency between the number of scenarios run and the input parameters used for different pathways. In the revised modeling the number of scenarios and input values are the same across all pathways.

More comprehensive and spatially explicit set of emission factors: The land conversion estimates made by GTAP are disaggregated by world region and agro-ecological zones (AEZ). In total, there are 19 regions and 18 AEZs. In the original modeling, each region had separate emission factors for forest and pasture conversion to cropland but these emission factors did not vary by AEZ within each region. Because land conversion estimates within each region differ significantly by AEZ and both biomass and soil carbon stocks also vary significantly by AEZ, emission factors specific to each region/AEZ combination are appropriate.

ARB contracted researchers at UC Berkeley, Stanford University, and UC Davis to develop the agro-ecological zone emission factor (AEZ-EF) model. The model combines matrices of carbon fluxes with matrices of changes in land use by land-use category projected by the GTAP model. The AEZ-EF model contains separate carbon stock estimates ($Mg\ C\ ha^{-1}$) for biomass and soil carbon, indexed by GTAP AEZ and region. The model combines these carbon stock data with assumptions about carbon loss from soils and biomass, mode of conversion (i.e., whether fire is used), quantity and species of carbonaceous and other GHG emissions resulting from conversion, carbon remaining in harvested wood products and char, and foregone sequestration. The model relies heavily on IPCC greenhouse gas inventory methods and default values, augmented with more detailed and recent data where available. Details of the process used to estimate carbon stocks and translate these values into emission factors are given in preliminary reports submitted to ARB in September 2011.[40,41]

Revised yield response to price: In the GTAP model, the response of crop yields to crop price is determined by the yield-price elasticity value. In the original modeling, ARB used a yield-price elasticity value range of 0.2 to 0.4. In subsequent modeling,

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[39] Tyner, W., F. Taheripour, Q. Zhuang, D. Birur, and U. Baldos, July 2010: *Land Use Changes and Consequent CO2 Emissions due to US Corn Ethanol Production: A Comprehensive Analysis*, Revised Final Report, Department of Agricultural Economics, Purdue University.

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

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

Purdue researchers have used a single yield-price elasticity value of 0.25 based on an econometric estimate made by Keeney and Hertel.[42] The elasticity subgroup, as part of its final Expert Workgroup recommendations suggested that ARB should maintain a value of 0.25 for this elasticity.

In contrast, the independent reviewer Steve Berry concluded that there is little relationship between changes in crop yields and price.[43] In this report, Professor Berry demonstrates that several research papers, including those which form the basis of the Keeney-Hertel yield-price elasticity estimate of 0.25, find that the yield-price elasticity cannot be distinguished from zero. Furthermore, in recent work with Wolfram Schlenker, Professor Berry uses an instrumental variables approach to estimate the "net yield" response to price. When crop prices rise there are two possible effects on yield. First, the yields on existing land may increase as farmers invest in inputs and technology to increase yields and maximize profits. Second, new land may come into production that has a different yield as compared to the existing land. The net yield elasticity takes both of these effects into account. Berry and Schlenker conclude that the net yield elasticity is near zero and that observed yields are generally explained by a very nearly linear "technology" time trend combined with the observed set of weather variables. Based on this conclusion, they provide an illustrative calculation that shows that if newly converted land is only two-thirds as productive as existing cropland, the short-run yield-price elasticity value should be no more than 0.1.[44]

Revised demand (food/feed consumption) response to price: The GTAP model predicts that an increase in biofuel production will lead to increased crop and food/feed commodity prices. These increases in prices in turn lead to an increase in supply of crops (through area expansion and potentially through increase in yields) as well as a decrease in demand for crops. The decrease in demand for crops occurs through substitution of biofuel co-products (e.g., dry distillers' grain and solubles [DDGS]) for animal feed, reduced direct human consumption of crops, and reduced human consumption of livestock, which in turn leads to reduced consumption of crops for feed. The reduction of food and feed consumption has a very significant effect on the amount of land conversion and consequently the LUC carbon intensity value. Using the same model used for ARB in the original modeling, Hertel et al. held global food consumption constant using a series of country-by-commodity subsidies.[45] Holding food consumption fixed resulted in an increase in LUC carbon intensity of 41 percent for corn ethanol (from 27 to 38 g/MJ).

The effect on LUC from reduced food and feed consumption is similar in other studies using different models. The EU Joint Research Center (JRC) performed a comparison

[42] Keeney, R., and T. W. Hertel. 2008. "The Indirect Land Use Impacts of U.S. Biofuel Policies: The Importance of Acreage, Yield, and Bilateral Trade Responses." GTAP Working Paper No. 52, Center for Global Trade Analysis, Purdue University, West Lafayette, IN.
[43] S. Berry. January 4, 2011. Report to ARB: Biofuels Policy and the Empirical Inputs to GTAP Models. Posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/010511-berry-rpt.pdf
[44] Berry, S. and W. Schlenker. August, 2011. Technical Report for the ICCT: Empirical Evidence on Crop Yield Elasticities posted online at http://www.arb.ca.gov/fuels/lcfs/09142011_iluc_sbreport.pdf
[45] Hertel et al., Effects of US Maize Ethanol on Global Land Use and Greenhouse Gas Emissions: Estimating Market-mediated Responses, Bioscience, 2010, 60(3), 223-231.

of LUC estimates using different models[46]. FAPRI, GTAP, and IMPACT models all show a significant reduction in LUC because of the reduced consumption of food and feed. For most scenarios the LUC credit ranged from 30 to 50 percent, although there were some scenarios with credits above and below this range. The one exception is the LEITAP model, which shows very little reduction in food and feed consumption but also gives much larger LUC estimates than the other models. Therefore, it does not appear as if GTAP is assuming a food and feed consumption response that is any different than most other models used to estimate LUC. However, it is likely that government policy interventions to hold food prices constant are not captured in the model.[47] The overall impact of these policy interventions on food production and consumption is unknown.

If the models are properly estimating the response of food and feed consumption to price changes induced by biofuel expansion, the potential impacts on human welfare are significant. These impacts are estimated in reports published by De Hoyos and Medvedev[48] and by Goklany[49]. De Hoyos's work estimates the price increases and poverty effects from the growth of crop-based biofuels over the time period of 2004 to 2010 due to existing global mandates for corn and sugarcane ethanol and biodiesel (e.g. the Renewable Fuel Standard). The modeling suggests that food commodity price increases, occurring in response to biofuel production, are heavily biased toward poorer regions of the world. In turn, these price increases are estimated to result in an additional 32 million people falling below the extreme poverty level and an additional 47 million falling below the moderate poverty level for the time period of 2004 to 2010. The increase in poverty is concentrated in two regions: South Asia and Sub-Saharan Africa, with by far the greatest impact in South Asia. Goklany's work builds upon De Hoya's results and develops what he describes as an "exploratory analysis" that provides an "order of magnitude" estimate of death and disease increases in developing countries. Goklany estimates 192,000 hunger-related excess deaths in 2010 and 6.7 million Disability Adjusted Life Years (DALYs) lost to hunger-related disease in response to global biofuel expansion between 2004 and 2010.

We want to be careful to point out that the estimates presented by De Hoyos and Medvedev and by Goklany are relevant to existing crop-based biofuel production levels that are largely mandated by government programs. The market signal from the California LCFS to increase production of crop-based biofuels relative to the existing global mandates is expected to be extremely small. Moreover, this market signal is expected to diminish over time as second- and third-generation biofuels become commercialized and replace crop-based biofuels as viable alternative fuels within the LCFS.

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[46] JRC Scientific and Technical Reports, EUR 24485 EN – 2010, Indirect Land Use Change from increased biofuels demand: Comparison of models and results for marginal biofuels production from different feedstocks.
[47] Tyner, W., September 2011: *Calculation of Indirect Land Use Change (ILUC) Values for Low Carbon Fuel Standard (LCFS) Fuel Pathways*, Interim Report posted online at http://www.arb.ca.gov/fuels/lcfs/09142011_iluc_wtreport.pdf .
[48] De Hoyos and Medvedev, "Poverty Effects of Higher Food Prices – A Global Perspective" The World Bank, March 2009
[49] Goklany, "Could Biofuel Policies Increase Death and Disease in Developing Countries?" Journal of American Physicians and Surgeons, Spring 2011.

As part of the September 2011 interim report prepared for ARB, staff asked Professor Tyner to perform a sensitivity analysis on the effect of food consumption changes on the LUC estimate.[50] In addition to model runs using the standard GTAP response of reduced food consumption to price increases resulting from expanded biofuel production, two additional scenarios were run:

- Holding food consumption constant in developing countries using a series of country by commodity subsidies
- Holding food consumption constant worldwide using a series of country by commodity subsidies.

The results of these sensitivity runs show that the LUC estimate is highly sensitive to the allowed reduction in food consumption within the model. ARB staff is evaluating these sensitivity runs as well as seeking stakeholder comments.

Increased flexibility of crop switching in response to price signals: The GTAP parameter that governs the acreage shift among alternative cropping industries in response to shifts in relative prices was calibrated to historical data from the 1900s. During this time period, government programs, not relative price, largely drove farmers' decisions on which crops to plant. Recently, Purdue researchers performed a regression analysis to test the hypothesis that farmers now respond to relative crop prices more than what was observed prior to 2000. They conclude that between the years of 2000-2010, changes in corn and soybean revenues were a major driver of changes in corn acres.[51] Similar regression analysis for earlier time periods shows no significant relationship. For this reason, they increased the land supply transformation elasticity, which governs the degree to which land is switched from one type of crop to another, from -0.5 to -0.75.

Incorporation of an endogenous yield adjustment for cropland pasture: Cropland-pasture is currently used primarily as an input to the livestock industry. As cropland-pasture is converted to dedicated crop production in response to biofuel expansion, land rents will rise, which may lead to investments to increase productivity of the land. This potential response led researchers at Purdue University to define a module to link productivity of cropland-pasture with its rent through an elasticity parameter.[52] However, Purdue researchers acknowledge that there is no empirical basis for the elasticity parameter proposed for this endogenous yield adjustment.

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

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

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

iii. LUC Values for Additional Pathways

LUC carbon intensity estimates for several new pathways will be developed as part of longer-term modeling work to be performed by researchers at Purdue University over the next two years. These pathways include:

- Sorghum ethanol
- Palm oil biodiesel
- Corn oil biodiesel
- Canola oil biodiesel
- Cellulosic ethanol
- Cellulosic bio-gasoline and bio-diesel

iv. Long-term Issues for Research

Researchers at Purdue University are under contract to explore longer-term model changes, most of which were recommended by the Expert Workgroup. These issues are listed below with reference made to the Expert Workgroup subgroup, independent reviewer final report, or Purdue report which describes the recommendation or model revision:

- Consider a broader range of significant indirect emissions from land use changes such as, but not limited to, those related to livestock and rice production and from crop switching.[53]
- Consider accounting for the effects of non-Kyoto climate forcing gases and particles (e.g., black carbon) in addition to carbon dioxide, methane, and nitrous oxide.[54]
- Explore a modeling framework that allows for the dynamic nature of land use change that can incorporate time dependent changes such as technology driven yield improvements and food demand (influenced by the dynamics of economic and demographic change). The modeling framework will likely involve use of the dynamic version of GTAP (GTAP-DYN).[55]
- Evaluate alternative approaches to calculating yields on new agricultural lands based on statistical analysis of climate and management factors using updated datasets.[56] Estimates of yields on newly converted lands should also factor in economics of land selection.[57]
- Continue to update and improve the land pools within GTAP deemed to be accessible for conversion to cropland. Additional land pools may include

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

"inaccessible" forests; unmanaged shrub land, grassland, and savanna; idle/fallow/abandoned cropland; and other marginal (low productivity) lands.[58]

- Evaluate alternative approaches to how the model determines which land types (e.g., forest or pasture lands) are converted to cropland. The evaluation involves either a significant change in model structure (changing the CET function as recommended by the elasticity values subgroup) or the use of land conversion probabilities for each region of the world which are exogenous to the model. Currently the model estimates both the amount of land converted to crops and the type of land converted. Observed land conversion probabilities could be used to better calibrate the model estimates of type of land converted (i.e., calibrate the CET function parameter on a regional level). Alternatively, the model could be used to predict only the amount of land converted and observed data for land conversion probabilities could be used to estimate the type of land converted.[59,60]
- Evaluate the use of Armington versus Heckschler-Ohlin structures for modeling international trade. The use of Armington structure for trade in GTAP, although appropriate in the short term, may be unrealistic over the long term. Armington assumptions give much preference to meeting increased demand with domestic production or from normal trading partners. In contrast, the Heckschler-Ohlin structure assumes similar crops of different origin are nearly perfect substitutes[61,62]
- Characterize the uncertainty in each major model component to allow the propagation of uncertainty through an integrated model of indirect effects.[63]
- Compare alternative methodologies for time accounting as research results become available in the peer-reviewed literature.[64]
- Ensure consistency in co-product treatment between direct and indirect effects modeling and conduct a comprehensive sensitivity analysis to better understand the model response to different values for the elasticity of substitution between energy and protein feedstuffs.[65]
- Consider constraints on use of irrigation as part of the LUC modeling as presented in recent work by researchers at Purdue. In July 2011, Purdue researchers presented a paper at the Agricultural and Applied Economics Association meeting which explored the role of irrigation in biofuel induced LUC estimates.[66] In this study, the

[58] Land Cover Types Subgroup, Final Report to the LCFS Expert Workgroup, November 22, 2010 posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[59] Ibid.
[60] Elasticity Values Subgroup, Final Report to the LCFS Expert Workgroup, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[61] S. Berry. January 4, 2011. Report to ARB: Biofuels Policy and the Empirical Inputs to GTAP Models. Posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[62] J. Reilly, November 4, 2010, Report to ARB: GTAP-BIO-ADV and Land Use Emissions from Expanded Biofuels Production, Posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[63] Uncertainty Subgroup, Final Report to LCFS Expert Workgroup, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[64] Time Accounting Subgroup, Final Report to the LCFS Expert Workgroup, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[65] Co-Product Credits Subgroup, Final Report to the LCFS Expert Workgroup, December 8, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm
[66] Taheripour, F., T. Hertel, and J. Liu, July 2011, *The Role of Irrigation in Determining the Global Land Use Impacts of Biofuels*, presented at the Agricultural and Applied Economics Association's 2011 AAEA and NAREA Joint Annual Meeting, Pittsburg, PA.

authors developed a new model version which distinguished irrigated and rain fed crops and placed constraints on the expansion of irrigated cropland.

b. *Modeling of Indirect Effects for Fuels Other than Biofuels*

i. *Contracts*

ARB has a short-term contract with Adam Brandt (Stanford University), Jim Bushnell (UC Davis), and Chris Knittel (MIT) to create a plan of research needs for evaluating potential market effects of petroleum-based fuels in the LCFS.

ii. *Intentions for Future Work*

The "Indirect Effects of Other Fuels" subgroup of the Expert Workgroup made the following recommendations for analysis and research:[67]

- Conduct an analysis, including but not limited to economic modeling, of the marginal supply of oil, the marginal supply of natural gas, the potential market mediated effect on the electric power market of using increased quantities of natural gas in the transportation sector, and the impact of petroleum substitutes on refinery operations.
- Conduct a reevaluation of the marginal supply of electricity.
- Conduct an analysis of the substitution of fossil fuels with alternative fuels. The analysis should include all factors affecting the substitution process in the short-, medium-, and long-term (market power of the OPEC Cartel, correlation between production cost and carbon intensity, predictions of conventional and unconventional fuels).
- Conduct a preliminary scoping analysis of the potential direct and indirect effects of upstream heavy metal mining and processing and if significant effects are identified, conduct an analysis of these effects.

As mentioned above, ARB currently has a contract to investigate potential market effects of petroleum-based fuels and plans to enter into similar contracts to investigate market effects within the natural gas and electricity sectors.

D. *Summary and Conclusions*

ARB is committed to using the best available science in performing the lifecycle assessments and determining carbon intensity values for transportation fuels. ARB recognizes that lifecycle assessment of transportation fuels and, in particular, LUC modeling will evolve over time and therefore carbon intensity values may likewise change. However, ARB is also cognizant that potential investors in low carbon fuels to meet the demands of the LCFS require some certainty that the carbon intensity values will not change frequently and significantly. This apparent dichotomy leads to several very important questions including:

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[67] Indirect Effects of Other Fuels Subgroup, Final Report to the LCFS Expert Workgroup, 2010, posted online at http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/010511-final-rpt-alternative-modeling.pdf

- What are the criteria for determining whether new studies merit consideration and what is the process for incorporating future advances into the regulation?
- What potential impacts do the advances have on stakeholders? The regulation?
- If updates to the lifecycle methodology lead to shifts in the carbon-intensity for a particular or set of fuels, how should the compliance schedule be adjusted to take this into account and ensure a consistent market signal?
- How do we balance the need for market certainty with the need for timely integration of advancements in lifecycle analysis?

In response, ARB understands that it must balance improvements in lifecycle assessment modeling with the need for some degree of market certainty. We believe that the requirement for periodic program reviews, the deliberate and measured response of ARB to new studies and model updates, the full public process used by ARB for changing LUC carbon intensity values and compliance schedule targets, and the Method 2 certification process described in this chapter should provide both a strong signal of market certainty while providing flexibility for individual fuel producers to quickly receive a direct carbon intensity value that is representative of their fuel pathway.

Should staff propose, and the Board approve, modifications to CI values in the Lookup Tables due to advances in lifecycle analysis, and those modifications impact the LCFS compliance schedule, the revised CI values would presumably take effect at the beginning of a new compliance period (i.e., January 1st) for ease of implementation.

V. Technology Assessment, Supply, and Availability

A. Introduction

This chapter addresses both a status update on transportation fuel technologies, as well as updates on supply and availability of these fuels, the infrastructure needed for these fuels, and the vehicles needed to use the fuels. The topics lead to a discussion on investment, both public and private, into "second generation" biofuels—that is, the biofuels on the horizon. The chapter also includes a discussion on how to incent these ultra-low-carbon biofuels. The technology assessment section of this programmatic review deals primarily with analysis of technology that is available, as of 2011, to help fulfill the requirements of the LCFS and the technology that is expected to come on line in the next several years. Further, this review also looks at potential hurdles or barriers to market penetration for these technologies. Moreover, this section discusses supply availability and impact on State fuel supplies, focusing primarily on analyses of current and future availability of fuels that may help fulfill the requirements of the LCFS.

This portion of the review includes the following topics, as specified in section 95489 of the LCFS regulation, which states that the:

> "Scope of each review shall include, at a minimum, consideration of the following areas:
>
> * * * * *
>
> (4) Advances in fuels and production technologies, including the feasibility and cost-effectiveness of such advances;
> (5) The availability and use of ultralow carbon fuels to achieve the LCFS standards and advisability of establishing additional mechanisms to incentivize the use of higher volumes of these fuels;
> (6) An assessment of supply availabilities and the rates of commercialization of fuels and vehicles;
> (7) The LCFS program's impact on the State's fuel supplies; and
> (11) Identification of hurdles or barriers (e.g., permitting issues, infrastructure adequacy, research funds) and recommendations for addressing such hurdles or barriers."

B. Technology Assessment, Fuel Supply, Vehicle Supply, Infrastructure and Barriers

This section addresses the current state of technology, the past and projected consumption or availability of fuel, past and projected vehicle populations, status of infrastructure, and any hurdles or barriers that the fuels might be encountering when trying to enter California's transportation fuels market, where data are available. This section is organized by fuel. Note that staff primarily relied on CEC data due to their robust analysis of the effects of California policies and regulations, including the LCFS, on the future supply and demand of fuel in California.

1. Gasoline

There are currently 12 refineries in California that produce gasoline for motor vehicle use. These 12 refineries produce the bulk of the gasoline that is consumed in California. In order to produce reformulated gasoline for the gasoline market, California refineries employ some of the most technologically advanced techniques employed by refineries, including reformation, alkylation, polymerization, and isomerization.

a. Historic consumption

California annually consumes four times more gasoline than diesel. In recent years, gasoline consumption held steady at around 16 billion gallons per year until 2008, when gasoline prices spiked due to crude prices soaring well over $100 per barrel. Annual gasoline consumption dropped by 800 million gallons—about four percent—with no recovery yet. The table below shows California gasoline consumption from 2006 to 2010, the latest year that data are available. As the data suggest, there has been very little fluctuation in the gasoline consumption since the original staff report was published in 2009. The data are from California Energy Commission (CEC) and Board of Equalization (BOE) analyses.

Table V-1: Gasoline Consumption in California, 2006-2010

Year	Gasoline (Million Gallons)
2006	15,821
2007	15,658
2008	14,917
2009	14,804
2010	14,861

b. Future Demand

The table below shows projected California gasoline consumption based on the Low and High Petroleum Demand cases from the CEC's Draft 2011 Integrated Energy Policy Report (IEPR). The high petroleum demand case ("Gasoline High") represents primarily faster economic recovery and low crude prices. The low petroleum demand case ("Gasoline Low") represents primarily increases in fuel efficiency and lower alternative fuel prices. Due to policies favoring low-carbon fuels and technology advancements, the long-term trend for gasoline demand is projected to decrease.

Table V-2: Projected Gasoline demand in California

Year	Gasoline Low (Million Gallons)	Gasoline High (Million Gallons)
2011	14,920	15,290
2012	14,620	15,470
2013	14,540	15,520
2014	14,350	15,480
2015	14,100	15,310
2016	13,980	15,180
2017	13,920	15,020
2018	13,680	14,820
2019	13,380	14,670
2020	13,110	14,540

c. Vehicles, Infrastructure, and Barriers

There are currently around 25 million gasoline-powered vehicles operating in California. These vehicles are predominantly light-duty passenger vehicles and are the primary method of individual transportation in the State. These vehicles fuel at terminals and dispensing facilities that predominantly sell gasoline. To date, short of a poor economy playing a role in lower consumption, there have not been any barriers to satisfying California demand for gasoline.

2. Diesel

California diesel fuel is produced at 15 refineries in California. In 2010, California refineries processed about 600 million barrels of crude and produced about ~104 million barrels of California diesel fuel, an average daily production of about 12 million gallons. Both federal and California regulations limit the sulfur content of diesel fuel to 15 parts per million by weight. In addition, the California diesel fuel regulations require a reduction in aromatic hydrocarbon content from conventional diesel fuel. California diesel fuel is produced through distillation of the crude into boiling-point range fractions, then catalytic reaction of the diesel portion of the distillate with hydrogen (hydro-treating) at high temperature and pressure to reduce the sulfur and aromatic contents of the fuel.

a. Historic Consumption

The table below shows California diesel consumption from 2006 to 2010, the latest year that data are available. The data are from CEC and BOE analyses. Diesel consumption saw a slight decrease in 2008, comparable to that seen in gasoline consumption. Though diesel use has increased slightly from 2009 to 2010, the overall consumption of diesel has not fluctuated significantly since the publication of the 2009 staff report.

Table V-3: Diesel fuel consumption in California 2006-2010

Year	Diesel (Million Gallons)
2006	3,736
2007	3,805
2008	3,429
2009	3,200
2010	3,295

b. Future Demand

The table below shows projected California diesel consumption based on the Low and High Petroleum Demand cases from the CEC's 2011 IEPR. The high petroleum demand case ("Diesel High") represents primarily faster economic recovery and low crude prices. The low petroleum demand case ("Diesel Low") represents primarily increases in fuel efficiency and lower alternative fuel prices. In general, projected increases in goods movement and increased use of diesel engines lead to an outlook of increasing diesel demand. This trend is likely to be complimented by current and future fuel economy policies because diesel vehicles are more fuel efficient than their gasoline counterparts.

Table V-4: Projected diesel demand in California

Year	Diesel Low (Million Gallons)	Diesel High (Million Gallons)
2011	3,280	3,310
2012	3,340	3,400
2013	3,410	3,480
2014	3,510	3,620
2015	3,590	3,720
2016	3,650	3,810
2017	3,700	3,890
2018	3,760	3,990
2019	3,800	4,080
2020	3,850	4,170

c. Vehicles, Infrastructure, and Barriers

The number of diesel vehicles in California has been increasing; in 2008, there were nearly one million diesel vehicles in the State. About 83 percent of these vehicles were commercial vehicles, with another eight percent being government vehicles and nine percent owned by private individuals. The distribution infrastructure for diesel is mature, although the number of dispensing facilities that offer diesel is likely to increase with the expected increase in diesel use for personal vehicles.

3. Fuel Ethanol

The primary source of ethanol in California has been ethanol derived from corn. Ethanol is currently blended into gasoline as an oxygenate at 10 percent by volume. Ethanol is also used as the principle component of E85. Both of these fuels are used for transportation in California. In this section, we will first discuss the sources of ethanol, then specifically its use in E85.

a. Historic Consumption

The volume of fuel ethanol consumed in California has increased significantly last two years. The increase has occurred because of the refiners decisions to increase the blend volume of ethanol from about 6 percent to 10 percent. This change was in large part the result of refiners need to comply with the provisions of ARB reformulated gasoline regulations. Currently, the volume of ethanol consumed is hovering around the blend limit of 10 percent of the gasoline volume. The table below shows California fuel ethanol consumption from 2006 to 2010, the latest year that data are available. The data are from CEC and DOE analysis.

Table V-5: Ethanol Consumption in California 2006-2010

Year	Ethanol (million gallons)
2006	950
2007	942
2008	990
2009	972
2010	1,493

b. Future Consumption

The amount of fuel ethanol that will be consumed in California over the next decade will be highly dependent on the supply and price of E-85 at retail fueling stations, the penetration of additional E85-compatible vehicles, and whether there is an increase of the current E10 blend limit. Ethanol pricing competitiveness, compared to petroleum fuels, will also have a significant influence on the amount of ethanol consumed in the future. In general, ethanol consumption in the State is expected to increase due to national and State level programs that mandate biofuels (the federal RFS2) or require petroleum fuels be displaced with lower carbon intensity fuels (the LCFS).

The table below shows projected California fuel ethanol consumption based on the Low and High Petroleum Demand cases from the CEC's 2011 IEPR, and assume that the biofuel volume requirements of the federal RFS2 will be implemented. The high petroleum demand case ("Ethanol High") represents primarily faster economic recovery and low crude prices. The low petroleum demand case ("Ethanol Low") represents primarily increases in fuel efficiency and lower alternative fuel prices.

Table V-6: Projected fuel ethanol demand in California

Year	Ethanol Low (Million Gallons)	Ethanol High (Million Gallons)
2011	1,503	1,541
2012	1,475	1,562
2013	1,566	1,621
2014	1,692	1,756
2015	1,875	1,944
2016	2,023	2,076
2017	2,154	2,225
2018	2,334	2,408
2019	2,510	2,564
2020	2,689	2,742

c. Vehicles, Infrastructure, and Barriers

The state of ethanol distribution and blending infrastructure in the state is mature, with most terminals having dedicated tankage and facilities to accommodate ethanol, however expansions in the infrastructure are likely to be necessary to accommodate an increase in ethanol use.

There are several remaining barriers in the way of further ethanol penetration. While the U.S. EPA has certified vehicles 2001 and newer to use E15 ethanol blends, this fuel cannot be legally sold yet under Federal or State regulations because fuel providers have not yet registered an E15 blend with U.S. EPA. As a practical matter, this means that ethanol used in California will be E10 and E85 for the near future. Further, ethanol cannot be shipped by pipeline within the current infrastructure, which means that it must continue to be delivered by less efficient trucks and trains. Additionally, there is currently no rack blending of ethanol with CARBOB to produce E85, creating blend stock and transportation inefficiencies.

d. Historic Consumption of E85

The table below shows California E85 consumption from 2006 to 2010, the latest year that data are available. The data are from CEC and BOE analyses.

Table V-7: E85 Consumption in California 2006-2010

Year	E85 (Million Gallons)
2006	2.23
2007	4.37
2008	26.6
2009	13.2
2010	9.98

e. *Future Demand of E85*

The demand for E85 is expected to grow. The growth in E85 use is dependent upon the rate of growth in E85-compatible, flex-fuel vehicles (FFVs), the price of the fuel, and the availability of E85. The table below shows the projected California E85 consumption based on the Low and High Petroleum Demand cases from the CEC's Draft 2011 Integrated Energy Policy Report. The high petroleum demand case ("E85 High") represents primarily faster economic recovery and low crude prices. The low petroleum demand case ("E85 Low") represents primarily increases in fuel efficiency and lower alternative fuel prices.

Table V-8: Projected future demand for E85

Year	E85 Low (Million Gallons)	E85 High (Million Gallons)
2011	13.9	15.0
2012	16.5	19.2
2013	142	88.0
2014	326	263
2015	589	521
2016	789	705
2017	963	914
2018	1,220	1,170
2019	1,480	1,390
2020	1,740	1,630

f. *Vehicles, Infrastructure, and Barriers for E85 Use*

Flexible fuel vehicles (FFVs) run on E85, gasoline, or a mixture of both. Because E85 is expected to play a part in meeting the LCFS standards, staff would need to estimate E85 volumes and the number of FFVs required to consume those E85 volumes. Staff also looked at how much E85 and FFVs would be required to meet the federal Renewable Fuel Standard (RFS2).

RFS2 requires fuel producers to use progressively increasing amounts of biofuels, culminating in at least 36 billion gallons of biofuel by 2022. Using the volume requirements, staff estimated the number of FFVs that will be needed to consume the volumes of ethanol mandated under RFS2 if the E19 blendwall is not increased. To determine the estimated number of FFVs, staff estimated 23.3 mpg for the average fuel economy for E10 gasoline and 17.4 mpg for E85 in the analyses for 2020. Staff used the same energy requirement to propel the vehicles (4.97 MJ/mi) for E10 and E85. Based on these assumptions, staff estimated a range of FFVs needed to comply with RFS2, which are shown in Table 2. The lower bound represents 100 percent refueling with E85. The upper bound represents 75 percent refueling with E85. The approach used in arriving at these estimated ranges is described in more detail below.

To determine future vehicle population, staff used the EMissionFACtors (EMFAC2007) model, which is used to calculate emission rates from all motor vehicles operating on highways, freeways and local roads in California, to forecast the number of 2012 model year and newer light-duty vehicles for calendar years 2012 through 2020.

To estimate future FFV population, staff determined upper- and lower-bound estimates. As an upper-bound estimate, assuming 100 percent refueling on E85, the EMFAC2007 projections were among the factors taken into consideration. This estimate also includes an assumption of the "Big Three" American automotive manufacturers (GM, Ford and Chrysler) producing 50 percent FFVs beginning in 2012. It was also projected that the Japanese manufacturers will ramp up their FFV production in California from 2012 through 2019 to 50 percent.

As a lower bound estimate, the estimated projection for FFVs is based on already known commitments from automobile manufacturers, including commitments from GM, Ford and Chrysler in doing 50 percent FFVs beginning in 2012, but not including commitments from the Japanese manufacturers. The table below illustrates the lower and upper bounds of the projected FFV population. Based on the calculations, there will be an ample number of FFVs available to consume E85 volumes that may play a role in meeting the LCFS.

Table V-9: Projected FFV population

Year	FFV Population (Lower Bound)	FFV Population (Upper Bound)
2010	359,000	359,000
2011	505,094	505,094
2012	686,143	702,082
2013	942,170	974,244
2014	1,194,293	1,325,782
2015	1,450,903	1,737,864
2016	1,698,482	2,194,012

Reaching the RFS and LCFS standards through E85 will also require increased access to retail infrastructure. A significant increase in E85 dispensers will be required in order to provide adequate levels of E85 to flex-fuel vehicle users. This increase in dispensers will have a cost range of $50,000 to $200,000 per installation.[68] The level of investment required makes E85 dispensers a difficult investment for retail station operators, who have no specific obligation to market and sell E85 under the RFS and LCFS, without an appropriate level of financial incentives from the fuel suppliers or other sources.

There is also substantial uncertainty associated with the future pricing of E85 to consumers. To induce owners of E-85 compatible vehicles to consistently use that fuel, E85 would need to be priced at a level that reflects its average fuel economy compared to E10 gasoline. Today, that price differential is supported by wholesale ethanol's price discount to gasoline, Renewable Identification Number[69] values, California's state fuel tax differential, and the Federal blender's credit (VEETC). The VEETC, at $0.385 per gallon of E85, is set to expire at the end of 2011. In the absence of an extension or

[68] Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report, Draft Staff Report, pg. 5, August 2011
[69] Renewable Identification Numbers are issued by U.S. EPA to fuels under RFS2.

other subsidy adjustments, the resulting price increase will either be passed along to the customer through higher prices at the pump, or retailers will tighten or eliminate their margins. Because E85 sales are not directly mandated but are instead dependent on consumer choice, parties regulated by RFS2 will need to price their fuels accordingly to meet the standards.

4. Fuel Ethanol Feedstocks

a. Corn (Grain) Ethanol

Since the original LCFS staff report was published in 2009, some facilities producing corn ethanol have increased their overall energy efficiency. These plants incorporate modern plant designs, which result in less energy use in the plant. The reduction in energy use is generally derived from incremental improvements in different production steps, including increases in ethanol yield, lower electricity use, installation of combined heat and power (CHP), lower temperatures for fermentation, more efficient enzymes, and more efficient natural gas boilers and other process equipment. In some cases, the reduction in carbon intensity (CI) can be attributed to use of low carbon-intensity inputs, such as biogas rather than natural gas powered equipment. Many of the facilities utilizing these technologies have been applying for custom CI values through the Method 2A/2B process. These facilities have submitted applications for over 100 additional pathways with total CI values as low as 73.2 gCO2e/MJ.

b. Sugarcane Ethanol

Sugarcane ethanol is produced in much the same way as corn ethanol. Ethanol derived from sugarcane is chemically indistinguishable from ethanol produced from other sources, and as such has all the same performance benefits and difficulties that ethanol from other sources have (e.g., transportation limitations and octane boosting properties). Sugarcane ethanol is expected to come primarily from Brazil, with some limited U.S. production in Hawaii, Florida and perhaps California. The carbon intensity of sugarcane ethanol from Brazil ranges from 58.4 to 78.9 gCO2e/MJ, or 18 to 39 percent less than gasoline.

c. Cellulosic Ethanol

Ethanol derived from cellulosic material is on the horizon. The most researched pathway to produce cellulosic 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 now to hydrolyze cellulose than starch. An alternative pathway involves gasification of cellulosic biomass to produce syngas. The syngas can be converted to ethanol using a modified Fischer-Tropsch synthesis or by fermentation techniques. More background on types of technologies can be found in Chapter III of the LCFS staff report.

The commercial production of cellulosic ethanol has not met the early expectations contained in RFS2 mandates. Under RFS2, U.S. EPA can respond to market conditions and revise the mandated volumes. For example, U.S. EPA reduced the

2011 mandated volume of cellulosic ethanol for the RFS2 from 250 million gallons to six million gallons after it determined there was inadequate production capacity to supply the targeted amount. EIA suggests that a more likely 2011 production total for cellulosic biofuels is approximately four million gallons. U.S. DOE is still processing grants to help stimulate cellulosic biofuels.

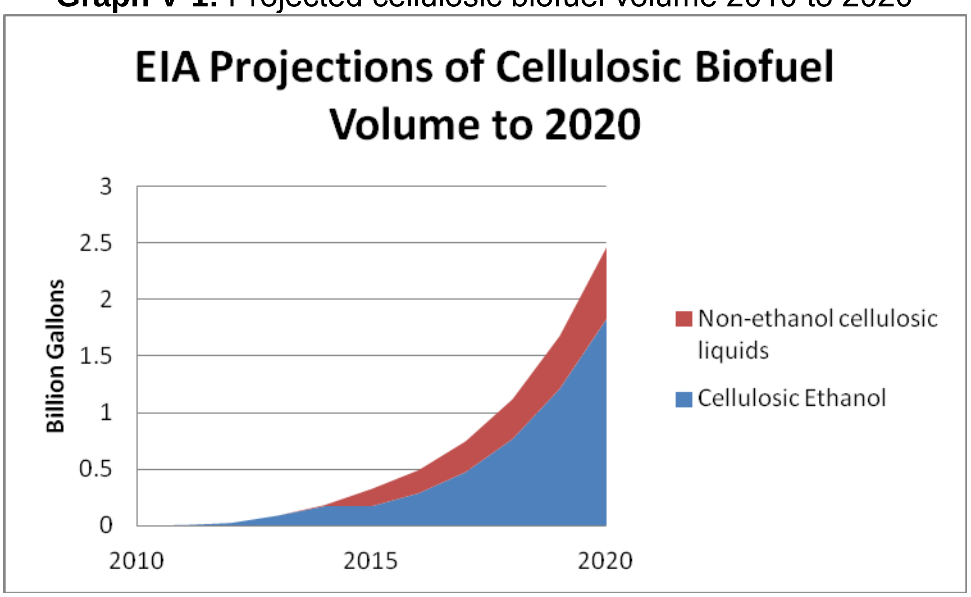
The prior consumption of cellulosic ethanol is essentially insignificant, and on the order the low millions of gallons for the entire U.S. Likely very little of that volume was consumed in California.

Under the RFS2 framework, the U.S. EPA annually must set a cellulosic ethanol volume standard that is based on projected production volume for the following calendar year. The annual standard adjusts the target volume for that calendar year from the RFS2 to the projected production volume. The U.S. EPA's projections of cellulosic ethanol production volume for the following year are required to consider independent projections by the U.S. Energy Information Administration (EIA).

The U.S. EPA and the EIA each conduct a comprehensive analysis of cellulosic ethanol projects at different stages of development in the United States. The cellulosic ethanol volume projections are based on identification of facilities that currently are in the planning stage, pilot stage or are expected to commence operation. EIA's *Annual Energy Outlook* reference case also tracks cellulosic ethanol trends. The 2011 *Annual Energy Outlook (*AEO 2011) reference case provides EIA's current projections of domestic cellulosic biofuel production through 2035.

The AEO 2011 reference case projects no cellulosic ethanol production during 2011 and projects a steady increase in cellulosic ethanol production to 2020, reaching a potential volume of approximately 2.5 billion gallons by 2020.

Graph V-1: Projected cellulosic biofuel volume 2010 to 2020



U.S. EPA set the cellulosic ethanol volume standard for the first time in 2010 at 6.5 million gallons, a reduction from 100 million gallons identified in RFS2. The 2011 standard was set at 6.6 million gallons, a reduction from 250 million gallons identified in RFS2; and the 2012 cellulosic ethanol volume standard has been proposed to be reduced from 500 million gallons to a volume within the range of 3.55 million gallons to 15.7 million gallons. The 15.7 million gallon cellulosic ethanol estimate includes 8.0 million gallons of cellulosic ethanol and 7.7 million gallons of non-ethanol cellulosic liquids that can substitute for gasoline. U.S. EPA listed nine facilities in the United States that are projected to have the potential to make cellulosic ethanol available for transportation use in 2012. The list consists of facilities that are either in the pilot stage, as of July 2011, or are expected to commence cellulosic ethanol production by the end of 2011. U.S. EPA has identified five facilities that may begin production of cellulosic ethanol on a commercial scale by 2013: Coskata, Enerkem, Poet, Abengoa, and Mascoma.

Table V-10: Cellulosic Ethanol Projections for 2010 - 2020

Year	RFS2 Cellulosic Biofuel Standard Volume Requirements[70] (Billion Gallons)	EIA cellulosic ethanol projections (Billion Gallons)	California's Proportional "Share" of Cellulosic Biofuel (Billion Gallons)
2010	0.10	0.00	0.00
2011	0.25	0.00	0.00
2012	0.50	0.02	0.002
2013	1.00	0.09	0.010
2014	1.75	0.18	0.020
2015	3.00	0.32	0.036
2016	4.25	0.49	0.055
2017	5.50	0.75	0.085
2018	7.00	1.12	0.127
2019	8.50	1.68	0.190
2020	10.50	2.47	0.279

The infrastructure and vehicle compatibility for cellulosic ethanol should not be any different than for corn ethanol. However, there are significant barriers to expanded production of cellulosic ethanol, primarily the infancy of the technology required to convert cellulose to sugar as well as the need for further investment.

5. Natural Gas

While there have not been technological advances in the infrastructure for delivery, natural gas use in the transportation sector—both as compressed natural gas (CNG) and liquefied natural gas (LNG)—has increased over the last few years. Table 1 below shows the consumption of natural gas as transportation fuel in California from 2006 to 2009. The consumption has increased at an average rate of nine percent per year. The increase could be attributed, at least in part, to anticipated fuel cost savings from

[70] Original RFS2 projections used in the 2009 U.S. EPA staff report.

natural gas relative to traditional fossil fuels, such as gasoline and diesel. On an energy-equivalent basis, natural gas fuel is less expensive than gasoline or diesel. If these fuel savings are maintained, natural gas use should continue to increase. The use of natural gas provides additional benefits, such as emission reductions for greenhouse gases, criteria pollutants, and toxics.

a. Historic Consumption

California vehicular natural gas consumption has been increasing. The table below shows California vehicular natural gas consumption from 2006 to 2010, the latest year that data are available. The data are from the EIA. As can be seen in the table, natural gas use has increased by about 50 percent over this period, from approximately 9,900 million standard cubic feet (mmscf) or 84 million gallons gasoline equivalent (millions GGE) in 2006 to 14,800 mmscf or 117 million GGE in 2010.

Table V-11: Vehicular natural gas consumption in California, 2006-2010

Year	Natural Gas, as CNG or LNG	
	(mmscf)	(million GGE)[71]
2006	9,889	84
2007	11,015	93
2008	11,705	99
2009	13,132	111
2010	14,798	125

b. Future Demand

California vehicular natural gas consumption is projected to increase. The increase is directly tied to greater penetration of new vehicles compatible with natural gas or vehicles converted to use natural gas, as well as installation of additional natural gas refueling infrastructure. The table below shows the projected California CNG consumption based on the Low and High Petroleum Demand cases from the CEC's Draft 2011 Integrated Energy Policy Report. The high petroleum demand case ("Natural Gas High") represents primarily faster economic recovery and low crude prices. The low petroleum demand case ("Natural Gas Low") represents primarily increases in fuel efficiency and lower alternative fuel prices.

[71] 118 scf of natural gas ~ 1 GGE (1 scf of natural gas = 930 Btu; 1 gallon of CA gasoline = 109,800 Btu)

Table V-12: Projected future demand for Natural Gas

Year	Natural Gas Low (Million GGE)	Natural Gas High (Million GGE)
2011	132	134
2012	135	142
2013	144	150
2014	155	158
2015	166	166
2016	177	174
2017	187	181
2018	195	188
2019	201	195
2020	207	202

c. Vehicles, Infrastructure, and Barriers

The expansion of the natural gas vehicle (NGV) population has played an important role in increasing volumes of natural gas use. NGVs can be categorized into two vehicle classes: light duty vehicles (LDVs) and heavy-duty vehicles (HDVs), which actually include what may be described as medium-duty vehicles (MDVs). The table below shows the NGV population from 2006 - 2010; these values have been estimated from the California Department of Motor Vehicles' (DMV) database. As shown in the table, the increased natural gas consumption was driven by the HDV-class growth. While the LDV was stagnant, the HDV has grown by more than 60 percent over this period.

Table V-13: Natural Gas Vehicles in California, 2006-2010

Year	LDVs	HDVs[72]	Total
2006	24,900	7,900	32,800
2007	25,200	8,600	33,800
2008	24,800	9,700	34,500
2009	24,800	11,300	36,100
2010[73]	24,800	12,900	37,700

Barriers to expanded natural gas usage include infrastructure and vehicle conversion. The infrastructure to deliver natural gas to consumers exists but a key missing element is the relatively low number of public stations. Fleet users have been the primary natural gas users to date, because they are able to install the necessary infrastructure on-site, and don't have to rely on public availability. The low number of vehicles that come stock with the ability to use natural gas leads to the necessity of conversion, which is costly and may not be warranted by the vehicle manufacturer.

[72] Includes small number of MDVs.
[73] Extrapolated from 2008-2009 numbers

6. *Biogas*

It has been projected that biogas generation could expand based upon the current sources of biomass and agricultural waste products. EPA's joint program, AgSTAR, projects that the number of anaerobic digesters could increase by at least tenfold.[74] Various studies by CEC and other California agencies suggest that biogas could displace diesel use (in California) by a few billion gallons depending on biomass allocation and technological availability.

Most renewable natural gas (RNG) is being produced outside the state and marketed into California for use via the natural gas pipeline distribution network. However, there are specific instances where renewable gas is entering California via truck or rail lines depending on the sales volume and transportation distance. Transport of RNG into the state through pipelines has an estimated transportation cost of $0.75 to $2.50/MMBtu. Projects within the state that are utilizing biomethane generated on-site include Waste Management's Altamont Facility and the Hilarides Dairy. There are other dairies operating anaerobic digesters; however, in most scenarios that energy is being converted to electricity. Waste Management's facility produces 13,000 gallons per day of LNG that support both the facilities energy needs and the fleet of waste haulers. The Hilarides Dairy in Lindsay generates its own fuel from anaerobic digestion lagoons, providing energy to its facilities and equipment.

a. *Historic Consumption*

To date there has been no significant use of biogas to power vehicles. However, there have been recent projects, such as the joint venture between Waste Management and Linde North America, to use LNG converted from landfill gas generated at the Altamont landfill to power Waste Management's LNG-powered refuse trucks.

b. *Future Demand*

Due to its low carbon intensity, it is expected that the use of biogas to power vehicles will have a long-term positive growth trend. However, it may be several years before this growth is realized due to the current commercial and regulatory barriers to distribution.

c. *Vehicles, Infrastructure, and Barriers*

Biogas is mostly methane, the same primary component in natural gas. As long as the gas can meet pipeline and motor vehicle standards for natural gas, it should be fully compatible with vehicles currently operating on natural gas, or those converted to operate on natural gas.

There are several barriers to bringing biogas to market, including: the low cost of fossil natural gas; the prohibition of injecting landfill gas into natural gas pipelines because of

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[74] Agricultural Biogas in the United States, Bramley et al., Tufts University Urban & Environmental Policy & Planning, May 2011, http://ase.tufts.edu/uep/Degrees/field_project_reports/2011/Team_6_Final_Report.pdf

concerns about vinyl chloride contamination; the cost of building an interconnect at each biomethane production facility; and the economic advantages in many cases of using biogas for electricity generation due to less fuel clean-up requirements. Further, permitting requirements in California can be more time-intensive and require an increase in capital investments due to their thorough nature; this may cause hesitation when constructing a biomethane gas processing and distribution station.

Currently, where biogas is allowed to be introduced into natural gas pipelines, a two million dollar investment is typically required to use an RNG source to build an interconnect line into the public utility pipelines. As noted, possible solutions for this problem include standardizing the interconnects or attaching a rate-based developer cost to each interconnect to reduce the long-term costs of potential products. Currently, there are over a thousand sites where biomethane could be produced but would currently require an investment upwards of two billion dollars to connect all of them into the pipeline.

In current situations where interconnects are not feasible, the fuel requires additional processing before transport. The costs associated with this endeavor require gas to be liquefied (compression and chilling costs) and then transported to another location for fueling. Biomethane gas is rarely generated in the same location that is effective for fueling a fleet; exceptions may be landfill and dairy equipment. In some instances, the pipeline may accept the gas into their system; however, with only one buyer the purchase price is not nearly as lucrative if there were multiple bidders for the gas.

The current federal tax credits incent the production of electricity on site when biomethane is produced, but this can be inefficient and may cause more emissions than if the gas were injected into the pipeline where a major natural gas electric power generation unit was converting the energy. If the same incentives were applied to both electrical generation and injection of renewable gas to the pipeline, the ability to sell to more than one buyer would generate additional security in the market. Note that the production of electricity from RNG sources is becoming more difficult in non-attainment air districts.

Capital investors need more assurances that the market will be stable to properly plan and allocate funding or incentives. Investors seek as much certainty as possible to make informed investment decisions; uncertainties may be the result of a new barrier being established or additional incentives that are directed towards competing fuels or technologies.

7. Biodiesel

Biodiesel is defined as a fatty acid mono-alkyl ester derived from vegetable oils, animal fats or other renewable oils. Biodiesel is commercially available, supplying about five million gallons of fuel in California in 2010, and about 350 million gallons of fuel in the U.S. Nationwide biodiesel production peaked in 2008 at 690 million gallons. If current production stays stable, the biodiesel industry will reach about 800 million gallons of production this year.

The primary feedstocks available for biodiesel production in California are waste vegetable oil, animal fats, inedible corn oil, canola oil, and soybean oil. Of these feedstocks, waste vegetable oil, animal fats, and inedible corn oil are waste feedstocks and may be used to produce biodiesel that has very low carbon intensity. The majority of biodiesel production facilities in California are multi-feedstock plants that are designed primarily to use these traditional waste feedstocks. Biodiesel production facilities should require little to no infrastructural change to accommodate algae oil, if algae oil becomes more readily available.

According to the LCFS staff report in 2009, California biodiesel production facilities had a combined nameplate capacity of about 35 million gallons. Staff's update conducted for this review has determined that nameplate capacity has doubled—to about 70 million gallons—as of 2011. According to U.S. EPA RFS2 facility registrations, as well as other sources, U.S. biodiesel production capacity is approximately 2.1 billion gallons.

a. Historic Consumption

The table below shows California biodiesel consumption from 2006 to 2010, the latest year that data are available. The data are from BOE.

Table V-14: Biodiesel consumption in California 2006-2010

Year	Biodiesel consumption (Million gallons)	Average biodiesel content
2006	19.610	0.53%
2007	17.459	0.46%
2008	11.702	0.34%
2009	6.921	0.22%
2010	5.398	0.16%

There are several factors that have likely played a part in the decrease in biodiesel consumption including: implementation of State Water Resources Control Board rules for underground storage tanks, delayed implementation of the RFS2, and the temporary expiration of the federal blender's tax credit in 2010. Further, there are multiple viewpoints regarding the impact of the economic downturn on biodiesel consumption. On the one hand, lower diesel fuel prices led to a similar reduction in biodiesel prices; but on the other hand, lower economic production may have led to companies and individuals having less capital and less ability to pay the marginal cost of biodiesel over diesel fuel.

b. Future Demand

The LCFS and RFS2 are expected to drive additional demand for biodiesel in California. The table below shows the projected consumption of biodiesel in California based on the Low and High Petroleum Demand cases from the CEC's Draft 2011 Integrated Energy Policy Report. The high petroleum demand case ("Biodiesel High") represents primarily faster economic recovery and low crude prices. The low petroleum demand case ("Biodiesel Low") represents primarily increases in fuel efficiency and lower alternative fuel prices. Please note that the CEC projections for biodiesel demand are lower than any of the illustrative scenarios in Chapter VI. ARB staff believes that the actual amount of biodiesel in the California market may be much higher, and may meet up to 20 percent of the diesel demand.

Table V-15: Projected future demand for Biodiesel in California

Year	Biodiesel Low (Million Gallons)	Biodiesel High (Million Gallons)
2011	52.7	84.2
2012	62.7	104.0
2013	61.8	103.3
2014	62.9	102.3
2015	63.8	100.4
2016	63.6	99.0
2017	63.2	98.2
2018	63.1	97.9
2019	62.8	96.4
2020	62.2	95.8

The federal RFS2 requires fuel importers and refiners to blend substantial amounts of biomass-based diesel fuel in the coming years. For example, 800 million gallons are required in 2011; 1 billion gallons are required in 2012; and 1.28 billion gallons are required in 2013. Many of the same companies are obligated parties under both the federal RFS2 and the California LCFS. These entities would appear to have an incentive to blend biodiesel in California because the same activity would help meet RFS2 obligations while also earning credits toward LCFS compliance obligations. For this reason, it is possible that biodiesel volumes in California could be significantly higher in the future than those reported in previous years or the projection above.

c. Vehicles, Infrastructure, and Barriers

Depending on the blend level, biodiesel can be used in all diesel engines with little to no modification. More than 60 percent of engine manufacturers currently include positive warranty statements for biodiesel up to and including 20 percent (B20). Some manufacturers include positive warranty statements for B100. All major manufacturers include positive warranty statements for blends of B5 and below. A number of manufacturers are currently engaged in testing programs to evaluate use of B20 in engines they produce, potentially leading to greater acceptance of biodiesel at B20 and higher blend levels.

Biodiesel is currently transported in the U.S. on the East and West Coasts in pipelines that do not carry jet fuel. However, no pipelines in California are shipping biodiesel currently, or are expected to ship biodiesel in the near-term. Federal Aviation Administration regulations prohibit the presence of non-approved additives or renewable components in jet fuel, which is the primary reason no pipeline companies in California will ship biodiesel (i.e., because they ship jet fuel and diesel in nearly all the pipelines in the State).

Additionally, the level of biodiesel allowed in ASTM jet fuel specifications is currently 5 parts per million (ppm). While biodiesel blends are commonly transported throughout Europe on pipelines that carry jet fuel, U.S. pipelines are larger, more complex, and carry more products than their European counterparts, making it more difficult to manage biodiesel levels below 5 ppm. A multimillion dollar joint research and testing project between the U.S. and Europe is currently underway to determine if a 100 ppm tolerance for biodiesel is acceptable.

The cost of installation of mid-stream storage and blending infrastructure has also prevented more B20 from entering the market. B20 requires local storage of biodiesel blendstocks at scale for efficient supply economics, and in many locations the necessary rail handling and rack-blending infrastructure does not exist.

8. Renewable Diesel

Unlike biodiesel, which has a tightly defined ASTM International quality and performance specification, renewable diesel is a broad term that encompasses many different production technologies. The most common and only commercial renewable diesel production technology is hydrogenation-derived renewable diesel (HDRD). HDRD is produced by hydroprocessing of vegetable oils, algal oils, or animal fats. HDRD can be produced standalone, through a dedicated batch or facility, or by co-processing with crude oil derived feedstocks. Both standalone and co-processed HDRD are liquid hydrocarbon fuels that have very similar chemical properties to petroleum diesel.

In addition to producing HDRD as a standalone product, some refineries may be capable of co-processing triglyceride feedstocks and petroleum feedstocks, resulting in a diesel product that is partially derived from renewable sources. Co-processed diesel may be produced by inserting the triglyceride feedstock into the refinery stream prior to the refineries hydro-treating unit resulting in n-paraffins with carbon chain lengths between 12 and 24 as well as propane, water, naphtha, and CO_2 by-products.

Co-processed HDRD may be produced by some refineries via the insertion of a triglyceride feedstock into the process prior to hydro-treating**,** resulting in a partially renewable end product. To date, however, there has been little experimentation with co-processing by major refiners due to the risk to valuable refinery assets as well as the opportunity cost of downtime for possible maintenance.

Stand-alone HDRD is not currently available in commercial quantities in California**,** but several demonstration and one commercial scale projects are currently operating throughout the United States. The most common current feedstock for HDRD in the U.S. is animal fat. For example, Syntroleum and Tyson have partnered on a joint venture, Dynamic Fuels, to produce renewable diesel derived from animal fat. The hydro-treated renewable diesel is produced in Louisiana in a recently completed facility with a nameplate capacity of 75 million gallons of fuel per year.

a. Historic Consumption

Currently, California renewable diesel consumption is limited to demonstration-scale projects of one to several vehicles. The consumption of renewable diesel in California has yet to take place on a commercial scale.

b. Future Demand

Because renewable diesel is a fully compatible replacement for petroleum diesel, the potential use of renewable diesel can theoretically approach the total volume of petroleum diesel, disregarding feedstock limitations. Currently, the major limiting factors for renewable diesel consumption and future demand are economic and transportation limits. For example, there are currently no commercial-scale facilities producing renewable diesel in California, which means that any future demand must be satisfied by new commercial production within the state, or out-of-state production facilities, requiring additional costs.

Like biodiesel, standalone HDRD is eligible for RIN generation within the federal RFS2 program's biomass-based diesel category. These required volumes increase from 800 million gallons in 2011 to 1.28 billion gallons in 2013 and offer a potential growth opportunity for the standalone renewable diesel industry. The amount of renewable diesel consumed will depend largely upon the amount of renewable diesel production that is commercially available and obligated parties' preference for that product or biodiesel. E2's survey of fuel producers found that the industry production estimates of renewable diesel exceed 500 million gallons in 2015[75].

c. Vehicles, Infrastructure, and Barriers

Currently**,** the major limiting factors for HDRD consumption and future demand are related to production, economics, feedstock availability, and transportation. For example, no commercial-scale facilities producing renewable diesel exist in California, meaning that any future demand must be satisfied by production facilities located outside the state; combined with the fact that HDRD typically requires more energy to produce than biodiesel, has higher capital costs, and yields less fuel from the feedstock utilized, this results in competitive challenges for the fuel in the commercial marketplace.

As a hydrocarbon fuel, renewable diesel is generally thought to be chemically similar enough to petroleum diesel such that it can be used in current vehicles with little to no modification. Currently, no engine manufacturer explicitly includes renewable diesel as a recommended fuel type, at any level, in its vehicle warranty statement. Therefore, there is some debate as to whether renewable diesel may be used in engines without voiding warranties. However, ASTM D975 (the industry standard for diesel fuel quality) has language which allows hydrocarbon oils, regardless of feedstock, to be components of diesel fuel, suggesting that as long as the fuel meets the specified properties of D975 it is acceptable as diesel fuel.

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[75] http://www.e2.org/ext/doc/E2%20Advanced%20Biofuel%20Mkt%20Report%202011.pdf

With the exception of co-processed HDRD at acceptably low levels of bio-derived component, HDRD requires many of the same infrastructure investments necessary for biodiesel. For example, at some point in the fuel stream the product must be stored and blended into petroleum diesel. However, unlike biodiesel, storage and blending may be done at more centralized locations, such as at refineries prior to introduction to the pipeline, since renewable diesel should technically be able to be transported by pipeline. Storage and blending infrastructure for renewable diesel is limited in California and would need to be expanded to accommodate significantly increased use of the fuel. However, if fuel blenders make and blend renewable diesel at the refinery site, distribution of HDRD will be invisible to the consumer and will require no additional investment beyond that made at the processing sites.

Co-processed renewable diesel receives relatively little government support, compared to other biofuels. Co-processed renewable diesel receives a tax credit that is half the amount provided standalone renewable diesel (and biodiesel) and does not qualify for the biomass-based diesel category within the federal RFS2 program.

9. Electricity

The largest deployment of electric vehicle infrastructure in history is currently underway through the U.S. Department of Energy's (DOE) Electric Vehicle (EV) Project. The Project includes the installation of approximately 7,000 residential chargers and 1,600 public chargers in California. The Project provides the opportunity to evaluate EV use and the effectiveness of charging infrastructure.

Electric vehicle growth may be further monitored through an existing state regulation proposed to include electricity. The Clean Fuels Outlet (CFO) regulation mandates alternate fuels' infrastructure when a certain number of vehicles using that alternative fuel are on the road.[76] Recently proposed modifications to the CFO regulation would include hydrogen stations and monitoring electric vehicle growth to better understand infrastructure challenges and needs.[77]

As the annual CI standards tighten throughout the decade, the amount of credits earned per EV diminishes somewhat because of the smaller difference between the CI of electricity and the CI of the lower standard. For example, in 2020, when the CI standard is 10 percent lower than 2010, staff estimates that battery electric vehicles would earn approximately 1.7 credits per vehicle, while plug-in hybrids would earn 1.3 credits per vehicle annually. The number of credits projected for the year 2020 varies considerably based on the projected number of electric vehicles. Based on these scenarios, LCFS credits available in 2020 could be 700,000 to 2,500,000 $MTCO_2e$. Compared to the total reduction of CO_2e in 2020, credits could be 3 to 10 percent of the total reduction. The potential value of the credits based on a range of $15 to $50 per credit, could range from $10 to $124 million.

[76] See title 13, California Code of Regulations, sections 2300-2318, at http://www.arb.ca.gov/fuels/altfuels/cf-outlets/cforeg2000.pdf, visited on October 17, 2011.
[77] See http://www.arb.ca.gov/fuels/altfuels/cf-outlets/meetings/07_13_11_cfo_workshop_presentation_rev3.pdf, visited on October 17, 2011.

a. Historic Consumption

The table below shows California vehicular electricity consumption from 2007 to 2010, the latest year for which data are available. The data are from CEC.

Table V-16: Vehicular electricity consumption in California 2007-2010

Year	Vehicular Electricity (Megawatt-hours)
2007	835
2008	841
2009	845
2010	856

b. Future Demand

The table below shows the projected consumption of gasoline in California based on the Low and High Petroleum Demand cases from the CEC's 2009 Integrated Energy Policy Report. The high petroleum demand case ("Electricity High") represents primarily faster economic recovery and low crude prices. The low petroleum demand case ("Electricity Low") represents primarily increases in fuel efficiency and lower alternative fuel prices.

Table V-17: Projected future demand for vehicular electricity in California

Year	Electricity Low (Megawatt-hours)	Electricity High (Megawatt-hours)
2011	960	917
2012	1,169	1,086
2013	1,617	1,479
2014	2,240	1,999
2015	2,869	2,536
2016	3,449	3,024
2017	3,969	3,460
2018	4,552	3,968
2019	5,113	4,468
2020	5,656	4,958

c. Vehicles, Infrastructure, and Barriers

Staff estimates that in 2011, there will be 5,000 to 11,000 electric vehicles operating in California. The estimate includes full-electric vehicles like the Nissan Leaf and Tesla Roadster, and plug-in hybrids like the Chevy Volt. Based on typical annual miles traveled using electricity supplied from the California grid, a battery-electric vehicle could earn about two credits in 2011; while a plug-in hybrid could earn one-and-a-half credits in 2011 (one credit is equal to one $MTCO_2e$). LCFS illustrative scenarios were based on 490,000 to 1,780,000 electric vehicles (both battery and plug-in hybrid) in 2020. The primary barriers to full utilization of electric vehicles are the costs associated with necessary infrastructure and the costs of the vehicles themselves, which are currently more expensive that traditional vehicles.

10. Hydrogen

Currently, hydrogen stations are co-funded through ARB Hydrogen Highway (nine locations, 60-140 kg/day) and CEC AB 118 funding (eight new locations, 180-240 kg/day). The major challenges in establishing hydrogen infrastructure include: 1) Fuel Cell Vehicle (FCV) roll-out projections are based on infrastructure being available ahead of vehicles, 2) good station coverage is needed to ensure consumer convenience, 3) early stations are costly, and 4) government funding is needed to offset capital and operations and maintenance (O&M) when fuel demand is low.

Based on a joint ARB and CEC survey of OEMs in 2009, the number of FCVs operating in California is expected to be less than 1,000 through 2013. However, the survey and OEM announcements indicates a marked increase in the number of FCVs from 2014 (approximately 2,000 vehicles) to 2017 (approximately 45,000 vehicles).

11. Butanol

As a renewable fuel, butanol has a number of advantages. Its similarities to gasoline allow it to be mixed with gasoline in any proportion. As a result, it has been called a "drop-in" fuel for internal combustion engines. In addition, because butanol does not cause water in gasoline or diesel to separate, it can be transported through existing fuel pipelines. Butanol has higher energy content and lower octane content than ethanol, and butanol has been demonstrated to work, without modifications, in vehicles designed for gasoline. The use of butanol as a commercial scale drop-in fuel has not yet been fully evaluated through the rigorous performance and environmental testing that is a necessary precursor to commercial use. Therefore, butanol's interactions with other gasoline components and its effects on combustion engines and post-combustion emissions are not fully understood. Further evaluation is required regarding blending characteristics, vehicle performance such as mileage and emission by-products, and other use characteristics. Additionally, butanol is currently undergoing the ARB multimedia evaluation process.

Biobutanol is produced by fermentation of sugar using either genetically modified organisms or carefully selected, naturally occurring microorganisms. Biobutanol production from renewable sources is currently at pilot scale and has not yet been demonstrated at industrial scale. Future possibilities include producing biobutanol using lignocellulosic material in a way similar to lignocellulosic ethanol production.

Currently biobutanol is not available in commercial quantities. Three companies are currently pursuing biobutanol production in the U.S.: Butamax (a joint venture of BP and DuPont), Cobalt biofuels, and Gevo. These three companies expect to have a combined production capacity of over 500 million gallons per year of butanol by 2015.

12. *Algal Biofuels*

Algae are generally considered an attractive potential feedstock for fuel because of the possibility of similar or relatively high yields compared to conventional crops, and the ability to use marginal or even desert land to cultivate the algae. Some estimates place algae's potential yield as high as 1,000 to 6,500 gallons of biofuel per acre, compared to about 600 gallons per acre for the most productive conventional crops.[78]

When producing fuel from algae, the algae can serve one of two purposes. The algae can act as a source of rapid-growing biomass, which is harvested, dried, and put through a gasification and liquefaction reaction to produce fuel. Alternatively, the algae can act as a bio-reactor to produce triglyceride oil, which can then be converted to fuel. The most commonly explored method for producing fuel from algae is to use the algae as a bio-reactor to produce triglyceride oil, which can then be converted to fuel.

Algae-derived triglyceride oils can be processed in the same way that vegetable oil or animal fat can to yield either biodiesel or renewable diesel, depending on the process employed. There are generally two methods of producing triglyceride oil from algae that are currently being explored: autotrophic growth using open ponds or photo-bioreactors (derives carbon from CO_2 and energy from light), and heterotrophic growth using fermentation (derives carbon from CO_2 using plant sugars as an intermediate and other non-CO_2 sources and energy from input heat).

Algae can be cultivated through a fermentation process to generate triglyceride oils. Algae oil fermentation can be completed using any source of available sugar, for example: corn starch, sugar cane, glycerol, and cellulosic materials. Algal fermentation processes are not fundamentally different from the yeast fermentation processes used to produce ethanol. Algal fermentation removes CO_2 from the atmosphere indirectly, by conversion of the carbon from the feedstock into triglyceride oil or fuel.

Algae can be cultivated through an autotrophic process using photo-bioreactors, which are closed systems employing plastic bags or enclosed transparent panels, or using open ponds in which the culture is exposed to the atmosphere. Autotrophic cultivation of algae for fuel was the subject of a large program funded by the U.S. DOE from 1978-1996, known as the Aquatic Species Program[79], which focused mainly on the open pond method. Autotrophic cultivation of algae removes CO_2 from the atmosphere directly by conversion of CO_2 into triglyceride oil or fuel. Additionally, co-placement with high CO_2 emitting facilities with photo-bioreactors holds promise due to the potential of algae to sequester a portion of the CO_2 emissions during growth.

13. *Renewable Gasoline*

Drop-in replacement gasoline derived from renewable resources is a technology that has experienced dramatic recent investment, largely due to policy signals such as the

[78] U.S. DOE 2010. National Algal Biofuels Technology Roadmap. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Biomass Program.
[79] U.S. DOE, 1998, A Look Back at the U.S. Department of Energy's Aquatic Species Program—Biodiesel from Algae. U.S. Department of Energy, Office of Fuels Development

LCFS and RFS2. The result has been two key developments, described by the E2 report in its survey of this industry. First is the finding that drop-in fuels, including renewable gasoline and renewable diesel, will be the main source of biofuels in the latter half of the decade. The study finds that “The 2015 production projections from companies show that the majority of volume will come from these fuels rather than ‘specialty’ fuels such as ethanol and biodiesel that require separate infrastructure. Thus, while ethanol and biodiesel will fill the short-term demand, the second half of the decade will be dominated by advanced drop-in biofuels." The second key finding is that that the risk has shifted from technology to production, specifically, that "the market risks are concentrated on financing and scaling up production facilities and the availability of affordable biomass feedstocks.

Renewable gasoline production is still in a pre-commercial stage, therefore, the outlook for these fuels has changed significantly since the inception of the LCFS analysis. Most current research endeavors relating to renewable gasoline are centered on the use of a gas-to-liquid technique with a modified catalyst to produce the desired target molecules in the gasoline range rather than in the diesel range. However, this approach seems to have yielded little so far due to the tendency of the catalysts to produce less desirable gasoline molecules, which may require further processing prior to use as a finished fuel. Alternatively, renewable gasoline may be produced directly by the use of algae, yeast, or other organisms, to produce gasoline range chemicals rather than ethanol or oil.

B. Investment

From start-ups to publicly traded companies, the advanced biofuel industry is experiencing significant activity and growth. Government regulations such as RFS2, the LCFS, and the European Fuels Quality Directive, in conjunction with rising oil prices and technological advances, have improved investment opportunities over the last five years.

1. Funding for Advanced Biofuels

The advanced biofuel industry is a new, cleantech sector with many market entrants and players. As can be expected in an emerging industry, the number of advanced biofuel companies changes constantly. Consequently, very few, if any, comprehensive lists of active biofuel companies exist. The absence of such a database does not represent a lack of data or activity, merely the difficulty in tracking an ever-moving target. However, the E2 advanced biofuels report does include a list of the active biofuel companies as of August 2011.

The Cleantech Group forecasts the market of low-carbon fuels at $33.4 billion by 2020. The forecast is nearly double the future market of energy efficiency ($17.3 billion), and significantly higher than renewable electricity ($20 billion).[80] To seize this opportunity, venture capitalists have invested at least $2.4 billion in active North American companies from 2007 through the second quarter of 2011. Additionally five biofuel

[80] Cheng, David, “California in Perspective: An Overview of State Energy Policies.” Cleantech Group, 2010.

companies have had successful IPOs in 2011, according to the E2 advanced biofuels report.

2. *Policies, Programs & Tax Incentives for Advanced Biofuels*

a. *DOE Guarantees*

The U.S. Department of Energy (DOE) has been routinely awarding grants and loans to emerging fuels and vehicle technology over the last several years. These funds have typically been directed toward advanced technology such as cellulosic fuel and electric drive vehicle technology. Much of the loan guarantees have gone to new demonstration or commercial facilities producing advanced biofuels. In addition to promoting advanced technologies and fuel, a major goal of the DOE funding is to promote energy sources that are secure and domestic.

b. *Assembly Bill 118*

AB 118 authorizes the CEC to spend about $100 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 (Nunez, 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.

Funds are awarded through the CEC process beginning with a Grant Solicitation for specific category; all proposals are then ranked by adherence to technical criteria, and those receiving priority rankings are funded. Mid-way into the second funding cycle of the Alternative and Renewable Fuel and Vehicle Technology Program, investment plans have guided the awarding of monies to six fuel categories. A total of $174 million dollars have been awarded as of the 2009-2010 plans including:

- $42.5 million for electric (charging infrastructure, medium- and heavy-duty advance vehicle demonstrations, manufacturing facilities and equipment);
- $15.7 for hydrogen (fueling stations);
- $5.1 million for natural gas (fueling infrastructure);
- $35.3 for biomethane (production);
- $10.5 million for ethanol (E-85 fueling stations, production incentive program, fuel production); and
- $8.2 million for biodiesel (upstream fueling infrastructure, and fuel production).

Under AB 118, ARB receives between $30 and 40 million annually (depending on revenues) for the Air Quality Improvement Program (AQIP) to fund clean advanced technology vehicle and equipment projects which reduce criteria pollutants and toxics and also provide climate change benefits. The Board approves an annual Funding Plan describing how AQIP funds will be spent each year. Two funding cycles have been completed, with $58 million in ARB funds awarded to date:

- $39 million for vouchers for California businesses to buy lower-emitting and fuel-efficient hybrid and zero-emission trucks and buses through the Hybrid Truck and Bus Voucher Incentive Project (HVIP). About 900 vehicles have been funded to date, and the Energy Commission has augmented the project with $4 million of its AB 118 funding to help meet demand.
- $9 million for consumer rebates toward the purchase of light-duty zero-emission or plug-in hybrid passenger vehicles through the Clean Vehicle Rebate Project (CVRP). About 2,000 vehicles have been funded to date, and the Energy Commission has augmented the project with $2 million of its AB 118 funding to help meet demand.
- $4 million for technologically promising demonstration projects needed for California to meet its longer-term air quality goals. Ten projects are in progress demonstrating advanced emission controls on locomotives, marine engines, and commercial lawn and garden equipment.
- $2.6 million to expand air district program which provide rebates to consumers who scrap old gasoline powered lawn mowers and replace them with zero-emission models. Over 12,000 lawn mowers have been replaced to date.
- $2 million for an off-road hybrid construction equipment demonstration project
- $1.1 million for a zero-emission agricultural utility terrain vehicle rebate project

On July 21, 2011, ARB approved the *Proposed AB 118 Air Quality Improvement Program Funding Plan for Fiscal Year 2011-12*. For this third funding year, staff proposed continued funding for its three largest project categories:

- $15 -21 million for the CVRP.
- $11-16 million for the HVIP.
- $2-3 million for advanced technology demonstration projects.

The AQIP is authorized through 2015, subject to annual funding appropriations by the Legislature.

In addition to the above programs, AB 118 provides the Bureau of Automotive Repair about $30 million annually through 2015 for an Enhanced Fleet Modernization Program. AB118 is a voluntary, vehicle-retirement program for high-polluting cars and light- and medium-duty trucks. The program is available statewide.

c. VEETC

The Volumetric Ethanol Excise Tax Credit (VEETC) is a federal policy to subsidize the blending of ethanol with gasoline in the United States. It is set to expire at the end of 2011, and indications are that its expiration will likely result in an ethanol price increase and an associated decrease in the demand for ethanol fuels. The effect on E85 is likely to be particularly severe, with the price of the fuel likely to increase significantly, possibly exceeding the price of gasoline. However, some analyses have concluded that the expiration of VEETC will result in lower wholesale prices of ethanol[81]. In spite of this, E85 will likely be required to meet the ethanol requirements of RFS2, therefore it will need to be priced by regulated parties accordingly to ensure its consumption.

C. Ultralow-Carbon Fuels

Currently, the LCFS does not contain any special provisions for the use of ultralow carbon fuels. Furthermore, there is not currently agreement on which fuels are actually ultralow carbon. Ultralow-carbon are incented because they have a CI commensurate with their lifecycle GHG emissions, and their use generates significant greater amounts of credit relative to many other lower carbon fuels. The concept of incenting the use of ultralow carbon fuels, with provisions specific to these fuels, was discussed during the development of regulation. However, such fuel-specific incentives ultimately were not included because the Board, as well as a fair portion of stakeholders, believed at the time of the hearing that the LCFS should remain fuel neutral. It was thought at the time that the inclusion of provisions for ultralow carbon fuels would create "winners and losers" within the program and make the LCFS less driven by market forces and performance and more driven by incentives and mandates. Incentives, such as credit multipliers, presumably would impact the real world reductions that would otherwise be achieved under the program.

The LCFS relies on the development of significantly lower carbon fuels in order to meet the 2020 goals. Ultralow-carbon fuels would have the potential to generate significant credits and be very desirable compliance options in the LCFS. In recognition of this, the LCFS regulation (section 95489(a)(5)) directs the Executive Officer, as part of the program reviews, to consider the advisability of establishing additional mechanisms to incent higher volumes of these fuels to be used.

To date, there is significant activity leading to the commercial production of ultralow carbon fuels. A report issued by E2 examined the potential production capacity of fuels with a CI of 24 gCO2e/MJ or below and found evidence that, domestically, the industry could produce over 3 billion gallons of ultralow carbon fuel by 2015[82].

If the development of these fuels in sufficient volumes does not occur under the current structure of the LCFS (based on the need for regulated parties to comply with the LCFS), special provisions within the regulation may aid in their development. However, because the LCFS is still in the infancy of its implementation, it is premature to determine that special incentives are needed to assist in the development of very low carbon fuels that will eventually be needed to comply with the more stringent goals of the later years of the program.

Nevertheless, it is appropriate to continue to monitor the development of ultralow-carbon fuels and evaluate whether to seek appropriate ways to incent the production of those fuels.

[81] Food and Agricultural Policy Research Institute. June 2011. "US Biofuels Baseline and impact of extending the $0.45 ethanol blenders credit"
[82] http://www.e2.org/ext/doc/E2%20Advanced%20Biofuel%20Mkt%20Report%202011.pdf

D. *Impact on State Fuel Supplies*

1. *RFS2*

Assuming the RFS2 requirements are implemented as currently written and that suppliers of petroleum fuels in California market their proportional share of the RFS2 volume mandates in the State, this federal program will eventually result in a more than doubling of biofuel use in the State from levels used in 2010. The RFS2 provisions are complementary to the LCFS in that much of the technology required to produce the lower carbon fuels required by the LCFS is the same technology required to produce the RFS2 fuels. However, the RFS2 calculates carbon intensity somewhat differently and does not provide the same incentive to all fuels as does the LCFS. Implementation of both of these regulations should lead to a more diverse fuel pool in California. Although the RFS2 regulation is meant to be technology forcing, the U.S. EPA so far has been revising the requirements to be more in line with the current state of technology. As such, at least in its early years, the RFS2 has not been as effective in driving investment as hoped.

2. *LCFS*

a. *LCFS Requirements Effect on Fuel Pool*

The LCFS does not require specific volumes of any fuel, and regulated parties have flexibility to choose the most cost-effective compliance options. Therefore it is not possible to accurately predict the impact it will have on State fuel supplies. However, the LCFS, in combination with other policies will almost certainly increase the amount of other alternative fuels that are consumed in the State, including natural gas, biodiesel, renewable diesel, electricity, and hydrogen, and correspondingly result in less use of petroleum as a transportation fuel.

The quantitative mix of fuels will be determined significantly by the RFS2 requirements, and beyond that the feedstock carbon intensity, combined with the production economics, should determine the remainder. For example, if a fuel has very low carbon intensity and is derived from low production cost feedstocks, that fuel will likely contribute significantly to the LCFS compliance in the State. Conversely, if a fuel has either high carbon intensity or is derived from relatively high production cost feedstocks, that fuel is unlikely to be used in large amounts in the in the State regardless of its status under RFS2.

b. *Supply and Demand*

Several stakeholders remain concerned whether the lower carbon fuels needed to comply with the LCFS will be available. Another concern is how to improve the estimate of the impacts the LCFS will have on the amount Californians pay for transportation fuels. The answers to these concerns depend on the future development of alternative fuels from an economic and technology advancement perspective. These advances are influenced by several factors including government policies at the national and state level, investment, and the price of crude oil.

In order for the lower carbon fuels needed to comply with the LCFS to be available two things must happen. First, the current state of technology and the ability to produce fuels from difficult feedstocks must advance in order to increase the commercial supply of these fuels. Second, the economics of these production processes must develop such that they can profitably invest in and build the needed production capacity to supply the needed volumes of low carbon fuels. Both of these advancements will be influenced by multiple factors.

Government policies, including fuel standards, tax credits, subsidies, and other policies all have the potential to lead to increased penetration of low carbon fuels in the market, in sufficient quantities, and at lower costs to the consumer. These policies can help to drive technological and economic development of low carbon fuels by providing economic incentives, or by incentives to comply with regulations. National and State policies of this nature should be complementary to the LCFS and should improve the ability of low carbon fuels to meet the fuel demands of the State.

Investment, whether by government or private entity, in low carbon fuels, is a necessity to ensure that the lower carbon fuels needed to meet the requirements of the LCFS become available. To the extent that investment in low carbon fuels is high enough and invested in fuels that have commercial viability, investment will be a key factor in whether the State's demand is met at the same time as the LCFS is fulfilled.

In addition to investment and government policies, availability and cost of natural resources will determine the effect the LCFS has on the cost of transportation fuels. For example, if natural resources, such as petroleum and natural gas, are abundant and prices are low, it will change the cost of low carbon fuels, and possibly increase the overall cost of fuel relative to conventional fuels. However, if natural resources become more scarce and prices for conventional fuels increase, low carbon fuels may be able to compete for relatively less cost or even a lower cost than conventional fuels.

3. Blend Limits

Currently, there are several alternative fuels whose market penetration, and therefore the options for them to contribute to both LCFS and RFS2 compliance, is limited by legal and other restrictions on the blend level of these fuels. This issue is distinct and different from availability based on prevalence of vehicles capable of operating on a specific fuel, such as natural gas. The primary fuels that are affected by this provision are ethanol and biodiesel.

Currently, ethanol blend limits are either at or below 10 percent by volume or E85 for use in FFVs. In order to change the limits, a State rulemaking must be undertaken to increase the limit beyond 10 percent. The U.S. EPA recently certified E15 for use in certain newer vehicles but regulated parties have not yet registered an E15 blend. Additionally the emergence of E15 in California as a transportation fuel will take several years of testing and rule development should the State decide to move in that direction.

Although ARB has no specific blend limit for biodiesel, the blends are effectively limited by two factors. First, the Division of Measurement Standards (DMS) of the California Department of Agriculture enforces the ASTM limits of 20 percent biodiesel blended with diesel fuel. Any biodiesel above this amount requires an exemption from DMS regulations. Second, most engine manufacturers recommend limiting the use of biodiesel to no more than five percent blends, which will likely limit purchasing habits of individuals to five percent biodiesel until more engine manufacturers raise that recommendation to 20 percent, as some have already done.

E. Summary and conclusions

The advanced biofuel industry is a new sector with many potential market entrants and players. As can be expected in an emerging industry, the number of advanced biofuel companies is rapidly changing. The Cleantech Group forecasts the U.S. market of low-carbon fuels at $33 billion by 2020. The forecast is nearly double the future market of energy efficiency ($17 billion), and significantly higher than renewable electricity ($20 billion).[83] To seize this opportunity, venture capitalists have invested at least $1.8 billion in active North American biofuel companies from 2007 through the first quarter of 2011, according to publicly available data. Such a level of investment in the biofuel sector reflects the willingness and confidence investors have in funding the eventual production and commercialization of advanced biofuels. Regulation, including both the RFS2 and LCFS, were highlighted by both biofuel panelists and the Cleantech Group report as the driving force for this investment to date. However, more investments will be needed for next generation biofuels to be commercially produced at high volumes.

[83] Cheng, David, "California in Perspective- A Review of State Energy Policies and Their Impact on High Growth Cleantech Markets." Cleantech Group, 2010.

VI. Meeting the Targets

A. Introduction

The LCFS establishes separate compliance schedules and annual CI targets through 2020 for gasoline, diesel, and their substitutes. During the early years, the "back-loaded" LCFS sets modest targets to allow for the long-term development of lower-CI fuels needed to meet the standard later in the decade (see Appendix A), and for increased market penetration by alternative-fueled vehicles using such lower-CI fuels. Meeting the targets may be achieved through various means, including but not limited to, purchasing low-CI biofuels, using credits previously generated, or acquiring credits from other parties to offset deficits.

For this review, the Panel was interested in the following: the capability of regulated parties to meet the targets in the near- and mid-term; the generation of credits to assist compliance in later years; the compliance challenges regulated parties might encounter in later years; and whether current data, coupled with plausible assumptions, are sufficient to estimate compliance capability for the next several years.

While this chapter provides staff's review of these topics with the Panel's input, it is important to reiterate that this 2011 evaluation was conducted during the first year of full program implementation. This assessment is based on the best information available, including the information from the first year of program implementation. Staff anticipates that more extensive data, reflecting actual compliance and investment strategies being used by regulated parties, would be available by the next scheduled formal review in 2014. Staff also plans to continue to update the Board on the implementation of the LCFS between the formal reviews.

To address the topics required to be addressed as well as those suggested by the Panel, this chapter is organized as follows:

- Meeting Near-, Mid-, and Long-Term Targets
  - 2009 Illustrative scenarios
  - 2011 Illustrative scenarios
  - First and Second Quarter 2011 Credit/Deficits Generated
- Strategies for and Challenges to Meeting the Targets
- Potential Flexible Compliance Mechanisms
- Summary and Conclusions

B. Meeting Near-, Mid-, and Long-Term Targets

Based on its assessment, ARB staff believes that regulated parties can meet the targets required under the LCFS. There are two reasons for this conclusion: 1) updated illustrative scenarios (discussed in section A2 of this chapter) show various plausible paths to meeting the targets; and 2) analysis of information submitted to the LRT shows substantial credits generated in Q1 and Q2 of 2011. These credits, along with credits to be generated in the next several years, in which the program targets are fairly modest, will likely be banked by the credit owners for use in later years, or traded to other regulated parties under favorable market conditions. Although many panelists have expressed concern that one or another assumption in the scenarios is unlikely to happen, the number of possible scenarios that meet the targets is an indication of the flexibility of the LCFS.

1. Original 2009 Illustrative Scenarios

For the 2009 rulemaking, staff produced a set of illustrative scenarios that relied, in part, on California receiving its proportional share of the cellulosic ethanol volumes originally mandated in the RFS2. The original 2009 scenarios showed that there are plausible pathways available to meet the 2020 LCFS requirements.

Since 2009, the U.S. EPA has significantly reduced the initial mandated volumes of cellulosic ethanol (the volumes for 2010 and 2011), and the EIA has significantly reduced its projections of cellulosic ethanol production over the next 10 years. The reduction in the amount of low-CI, cellulosic ethanol in the market has generated concerns by some parties that regulated parties might not be able to meet the LCFS requirements after the next couple of years. Therefore, the illustrative scenarios were updated to reflect current conditions to address the question of whether, and for how long, regulated parties could be expected to meet LCFS annual targets and if there is a need to adjust the compliance schedule.

2. Updated 2011 Illustrative scenarios

Based on current and developing fuel and vehicle technologies, feedstock availabilities, and other factors, ARB staff has analyzed a number of revised illustrative scenarios to examine potential outcomes under various circumstances. The objective of the scenarios is to help address questions regarding the ability of regulated to parties to meet the CI reduction targets required under the LCFS. Note that some Panel members have expressed concern that these scenarios have not undergone rigorous analysis to clarify the reasonableness of the assumptions. Staff acknowledges that these scenarios are for illustration only; they are not projections of how actual compliance will occur.

In this analysis, staff presents sixteen illustrative scenarios – eleven for gasoline and its substitute fuels and five for diesel fuel and its substitute fuels. These scenarios include a mix of fuels and strategies that could be deployed to satisfy the LCFS targets through 2020. As noted, these scenarios are different from the 2009 illustrative scenarios for various reasons, including the assumptions used and the substantial reduction in the RFS2 mandate for cellulosic ethanol. Appendix B provides a brief comparison of the main differences between the 2009 and 2011 illustrative scenarios. As the LCFS program moves forward, staff will continue to monitor the factors built into the scenarios.

The 2011 illustrative scenarios illustrate how the CI standards might be met, based on various assumptions about future conditions. These scenarios are not predictions or forecasts, but rather illustrations of plausible combinations of fuels that could meet the LCFS targets (along with the vehicles that would use such fuels). The scenarios shown in this report represent only a sample of the possible scenarios that could be evaluated. A full assessment of all such possible scenarios is beyond the scope of this report.

The rate of future fuel and vehicle technological development remains uncertain. The technologies that are most likely to produce commercial quantities of lower-carbon fuels, or the vehicles designed to use such fuels over the near- to mid- term could encounter delays. The development of other, currently less well-developed technologies, could achieve breakthroughs. In addition, 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.

a. Common Scenario Assumptions

For all the revised gasoline and diesel scenarios, staff used several common assumptions. The common gasoline and diesel assumptions are presented in Appendix C; these assumptions are based on regulatory mandates (e.g., low emission vehicle regulation) and expected technological advances.

b. Gasoline and Diesel Scenarios

As noted, staff developed eleven illustrative gasoline and five diesel scenarios using different assumptions as shown in Tables V-1 and V-2 below. For a more-detailed look at the scenarios in tabular form, please refer to Appendix C.

Table V-1. Summary of Updated 2011 Illustrative scenarios for Gasoline

Scenario 1: Cellulosic and Corn Ethanol Future; Credit Banking	• California gets about 85 percent of EIA cellulosic projections; E15 by 2016. • Low corn ethanol use in 2016 and after; large FFV use using E85 50 percent of the time; • Substantial early surplus credit generation before 2017; • Annual deficits generated between 2017 and 2020, but some credits remain after 2020;
Scenario 2: Increased cellulosic ethanol, FFVs and Credit Banking	• California gets nearly all (about 90 percent) of EIA cellulosic projections; E15 by 2016. • Low sugarcane ethanol use and low corn ethanol use in 2020; relatively low FFV use; • Fueling with E85 about 50 percent of the time before 2018 and about 60 percent of the time after; substantial early surplus credit generation before 2017; • Annual deficits generated between 2017 and 2020, but some surplus credits remain after 2020;
Scenario 3: Delayed Cellulosic Ethanol Future	• Delayed cellulosic ethanol introduction; mostly corn ethanol used until 2015; • Increasing sugarcane ethanol use through 2020; E15 by 2016. • California gets about a quarter to a third of EIA nationwide cellulosic projection; • High FFV use beginning in 2015 using E85 a high percentage of the time; • Surplus credits accumulate until 2019; • Deficits generated in 2019 and 2020, but some surplus credits remain after 2020;
Scenario 4: Lesser Cellulosic Ethanol Future	• Only corn and sugarcane ethanol until 2015; high corn and sugarcane ethanol through 2020; • Cellulosic ethanol introduced in 2015 up to only about a third of EIA nationwide projection for 2020; very high FFV use, fueling with E85 100 percent of the time; • Less surplus credit accumulation before 2019 than in Scenario 3; • Deficits generated between 2018 and 2020, but some surplus credits remain after 2020.
Scenario 5: Drop-in Fuel Future	• Small amounts of cellulosic ethanol begins in 2014; drop-in fuel begins in 2015; E15 by 2016. • Cellulosic about 25 percent of EIA 2020 nation-wide projection; • No FFVs; substantial surplus credits in early years; • Deficits generated between 2018 and 2020, but some surplus credits remain after 2020;
Scenario 6: Complete Technology Shift Future	• Only corn ethanol is used until 2014; sugar cane ethanol and cellulosic ethanol begin in 2014; Drop-in fuel begins in 2015; cellulosic about 40 percent of EIA 2020 nationwide projection; no FFVs; E15 by 2016. • Early credits generated with corn ethanol; compliance is achieved every year up to 2020; • Surplus credits from early generation remain after 2020;
Scenario 7: Complete Shift with FFV Future	• Similar to Scenario 6, but with a small number of FFVs operating on E85 50 percent of the time; early surplus credits remain after 2020; E15 by 2016.

Scenario 8: Complete Shift, Increased Ethanol Future	• Large number of FFVs operating on E85 50 percent of the time; E15 by 2016. • Sugarcane and cellulosic ethanol introduced in 2015; drop-in fuel starts in 2016; • Cellulosic about 25 percent of EIA 2020 nation-wide projection; • Compliance is achieved every year between 2011 and 2020, and early surplus credits are generated as in Scenario 7, which remain after 2020; • Less drop-in fuel than Scenario 7, but large number of FFVs used so that projected E85 use is in line with CEC projections; sugarcane ethanol and cellulosic ethanol begin in 2014;
Scenario 9: Complete Shift with FFV Future and E10	• Similar to Scenario 7; but with the use of E10 instead of E15; and with greater number of FFVs.
Scenario 10: Complete Shift, Increased Ethanol Future and E10	• Similar to Scenario 8; but with the use of E10 instead of E15; and with greater amount of cellulosic ethanol.
Scenario 11: Complete Shift, Less FFVs.	• Similar to Scenario 8; but with E10 instead of E15; and fewer FFVs. • Same drop-ins as Scenario 6.

Table V-2. Summary of Updated 2011 Illustrative scenarios for Diesel

Scenario 1: Soy Biodiesel Future	• Diesel is blended with non-conventional diesel initially at four percent in 2012 up to 20 percent by 2017 and thereafter. • Soy biodiesel is the predominant biofuel used through 2018 with increased use of unused cooking oil thereafter. • Deficits generated early in the program can be offset with additional gasoline credits until blends reach the appropriate volumes to be self-sustaining in 2013. • Annual deficits generated between 2017 and 2020, but some credits remain after 2020. • Natural gas use is included in all diesel scenarios
Scenario 2: Canola Oil Future	• Similar assumptions to Scenario 1; • However, also includes canola oil, which displaces other biodiesel feedstocks.
Scenario 3: Corn Oil Future	• Similar assumptions to Scenario 2; • However; also includes small amounts of corn oil.
Scenario 4: Diverse Biodiesel future	• Similar assumptions to Scenario 3; • However, also includes small amounts of tallow renewable diesel, further diversifying the mix of biodiesel types (i.e. soy, corn, canola and UCO) quantities.
Scenario 5:	• Similar assumptions to Scenario 4;

Drop-in Renewable Future	• However, also includes small amounts of drop-in renewable diesel in 2014 with moderate increases through 2020. • Introduction of renewable diesel significantly reduces amounts of soy biodiesel.

c. 2011 Illustrative Scenario Results

This section provides a summary of the results. The detailed results of the sixteen scenarios are provided within Appendix C. The results collectively represent outcomes that could result from the effects of various assumptions about future compliance options over the course of the LCFS compliance schedule. These assumptions covered a range of possible outcomes and were primarily formed by developing options that may be feasible in the time frames suggested and are complimentary.

The gasoline and diesel scenario results provide an illustration of how credits may be generated or deficits created given the assumptions inherent in each scenario. The scenarios consider: fuel and vehicle technologies (current and developing), the availability of low carbon blendstocks and fuels, and other factors. Each of the scenarios includes a mix of fuels that could potentially meet the LCFS targets. The results of the scenarios are presented as follows.

i. Gasoline Scenario Results

Table V-3 below summarizes the credits or deficits created annually under the various gasoline scenarios and the cumulative credit totals for the years 2011 to 2020. Note that a regulated party's compliance in a given year is determined by their cumulative credits, as annual deficits may be reconciled with credits earned in a previous year. The annual and cumulative credits and deficits are expressed in thousand metric tons (1,000 MTs); a positive value represents a credit, while a negative value represents a deficit. Positive cumulative balances or neutral balances indicate scenarios that meet the target overall for a given year.

Table V-3. Summary of Gasoline Scenario Credits/Deficits

Scenario	Credits/Deficits (1000 MTs)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Annual	556	714	550	410	131	827	-181	-599	-305	-267
	Cumulative	556	1,270	1,820	2,230	2,361	3,188	3,007	2,408	2,103	1,836
2	Annual	556	683	577	408	63	725	-118	-587	-171	-1,146
	Cumulative	556	1,239	1,816	2,224	2,287	3,012	2,894	2,307	2,136	990
3	Annual	556	572	184	39	-158	378	324	197	-523	-1,389
	Cumulative	556	1,128	1,312	1,351	1,193	1,571	1,895	2,092	1,569	180
4	Annual	556	661	406	117	-255	221	-13	-191	-315	-655
	Cumulative	556	1,217	1,623	1,740	1,485	1,706	1,693	1,502	1,187	532
5	Annual	556	572	184	6	-3	289	296	-96	-373	-892
	Cumulative	556	1,128	1,312	1,318	1,315	1,604	1,900	1,804	1,431	539
6	Annual	556	572	184	3	0	-3	4	3	1	5
	Cumulative	556	1,128	1,312	1,315	1,315	1,312	1,316	1,319	1,320	1,325
7	Annual	556	572	184	0	2	6	2	7	7	4
	Cumulative	556	1,128	1,312	1,312	1,314	1,320	1,322	1,329	1,336	1,340
8	Annual	556	572	184	4	7	5	2	1	-1	1
	Cumulative	556	1,128	1,312	1,316	1,323	1,328	1,330	1,331	1,330	1,331
9	Annual	556	572	184	0	1	-1	1	1	0	2
	Cumulative	556	1,128	1,312	1,312	1,313	1,312	1,313	1,314	1,314	1,316
10	Annual	556	572	184	4	4	7	1	-1	2	2
	Cumulative	556	1,128	1,312	1,316	1,320	1,327	1,328	1,327	1,329	1,331
11	Annual	556	572	184	0	1	2	0	3	3	0
	Cumulative	556	1,128	1,312	1,312	1,313	1,315	1,315	1,318	1,321	1,321

In general, all eleven gasoline scenarios show positive (green or darker shading) substantial cumulative credit balances from 2011 through 2020. The credit balances indicate that meeting the targets through 2020 is plausible under the assumptions included in the scenarios, despite some years having no credits or having annual deficits (yellow or lighter shading) at various points.

There are a number of useful observations that can be made based on an evaluation of the scenarios. For scenarios 1 and 2, the early use of low CI ethanol creates substantial credits before 2017 that can be banked and used in later years to offset deficits in those years. Although there are deficits generated in the latter years, there are sufficient credits remaining from the accumulated bank after 2020. Further, these scenarios show that cellulosic ethanol, even if used in low but gradually increasing levels, can reduce the demand for corn ethanol.

For scenario 3, the delayed penetration of cellulosic ethanol can result in deficits generated in 2015, with credits generated from 2016 to 2018 as cellulosic ethanol begins to penetrate the market. Even with those deficits, the scenario shows sufficient credits can be accumulated so that a positive balance can remain after 2020.

For scenario 4, credits are accumulated at a lesser pace than with scenario 3 and annual deficits would be generated from 2018 to 2020. Nevertheless, the accumulated credits are sufficient to ensure that surplus credits remain after 2020. If corn ethanol volumes remain near current levels, increased use of E85 in FFVs would be needed. By contrast, scenario 5 shows that if drop-in gasoline becomes available by 2015, no FFVs using E85 would be necessary to meet the LCFS targets.

For scenarios 6, 7, and 8, note that annual compliance is achieved through 2020 by using surplus credits generated through 2013. A small annual surplus is generated nearly every year from 2014-2020.

Based on the above, staff believes the illustrative scenarios evaluated show a variety of pathways for meeting the LCFS targets through 2020, even as the standards tighten in the latter years and it becomes more challenging for fuel providers to generate credits. As the LCFS program moves forward, staff will continue to monitor the factors built into the scenarios.

ii. Diesel Scenario Results

Table V-4 below summarizes the credits or deficits created annually under the various diesel scenarios and the cumulative credit totals for the years 2011 to 2020. As with the gasoline scenarios presented above, the annual and cumulative credits and deficits are expressed in thousand metric tons (1,000 MTs); a positive value represents a credit, while a negative value represents a deficit. Positive cumulative balances or neutral balances indicate scenarios that meet the target overall for a given year.

Table V-4. Summary of Diesel Scenario Credits/Deficits

Scenario	Credits/Deficits (1000 MTs)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Annual	110	17	1	3	-3	3	-1	0	0	1
	Cumulative	110	127	128	131	128	131	130	130	130	131
2	Annual	110	17	6	3	3	-1	2	0	-2	2
	Cumulative	110	127	133	136	139	138	140	140	138	140
3	Annual	110	17	6	3	-3	2	-2	-1	-1	-2
	Cumulative	110	127	133	136	133	135	133	132	131	129
4	Annual	110	17	-4	3	1	-3	2	4	2	-1
	Cumulative	110	127	123	126	127	124	126	130	132	131
5	Annual	110	17	3	-1	0	2	1	1	-2	3
	Cumulative	110	127	130	129	129	131	132	133	131	134

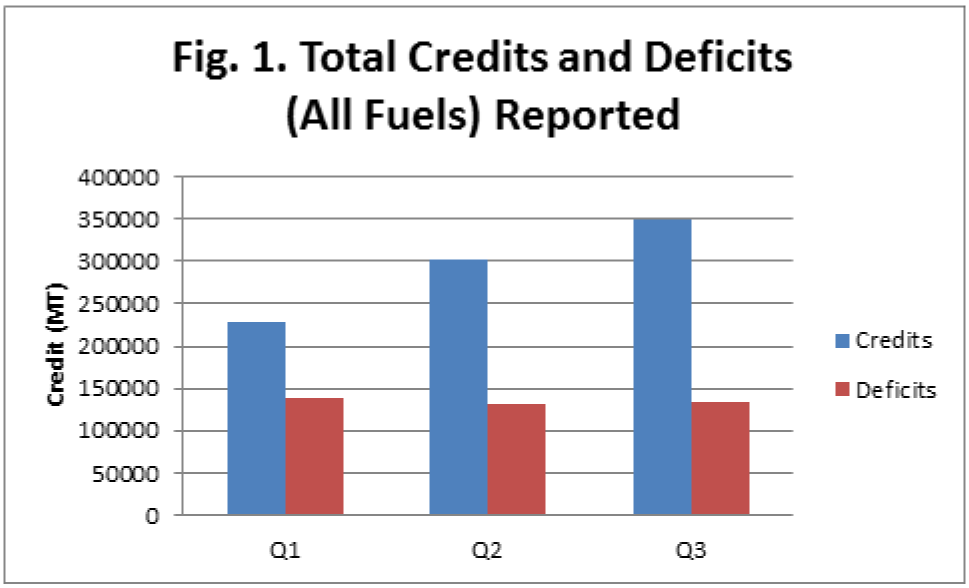
These diesel scenarios conservatively assume a gradual increase in biodiesel use from B0 in 2011 to B20 by 2017. In general, these diesel scenarios suggest that, during the first two years of the LCFS program, annual excess credits will be generated due to CNG use in the early years. After the first few years the increase in biofuels keeps up with the standards enough not to incur cumulative deficits.

Given the above considerations, surplus credits should continue to accumulate up to and after 2020. It should be noted that, given the large difference in carbon intensities between various biodiesel feedstock sources (e.g., soy oil, used cooking oil, canola oil, corn oil and tallow renewable diesel), credit generation outcomes were highly sensitive to biodiesel feedstock choice. Further, the above scenarios are based on a gradual penetration of biodiesel and renewable diesel and early current use of CNG. To the extent the use of biodiesel and renewable diesel is accelerated in the early years, along with alternative-fueled heavy duty vehicles (e.g., CNG/LNG vehicles), the accumulation of credits shown in the scenarios may occur faster than indicated.[84]

[84] ARB staff recently issued a biodiesel regulatory guidance explaining ARB's plans for proposing motor vehicle fuel specifications for B6 and above in a late-2012 rulemaking and plans to conduct further research involving B5 over a five-year timeframe. See http://www.arb.ca.gov/fuels/diesel/altdiesel/20111003BiodieselGuidance.pdf. This guidance is intended to provide certainty to the biodiesel and diesel industry with regard to ARB's rulemaking plans and thereby accelerate the introduction of NOx-mitigated B20 into the diesel fuel pool.

d. *First and Second Quarter 2011 Credit/Deficits Generated*

As the illustrative scenarios discussed above show, substantial credit generation in the early years can assist regulated parties in meeting the LCFS targets through 2020. The ability to generate early excess credits is shown by data from the LCFS Reporting Tool (LRT). Figure 1 below shows staff's analysis of the LRT data for the first three quarters of 2011. The figure shows that regulated parties generated about 225,000 metric tons (MT) of credits in the first quarter, about 300,000 MTs in the second quarter, and 350,000 MTs in the third quarter for a total of about of 875,000 MTs of fungible credits. The fungible credits compare favorably to the less than 425,000 MTs of deficits. In other words, the amount of "excess" credits (i.e., beyond those needed to offset the deficits) is about 450,000 MTs. To the extent that regulated parties bank these credits, the banked credits can provide substantial assistance to regulated parties in meeting the LCFS targets in the latter phase of the program.[85] [86]



Source: LCFS Reporting Tool.

C. *Strategies for and Challenges to Meeting the Targets*

1. *Strategies for Meeting the Targets*

Several potential strategies to meet compliance targets include: accumulating initial credits, diversification of product slate, and investment in the commercialization of new

[85] Regulated parties appear to be banking these credits in the absence of explicit provisions governing credit trading; staff is proposing explicit credit trading provisions in the upcoming December 2011 rulemaking to provide the "ground rules" for credit trading and other refinements to the LCFS regulation. See http://www.arb.ca.gov/fuels/lcfs/regamend/regamend.htm.

[86] The HCICO provisions dictate that credits may only be banked after reconciling the current year's deficit incurred by HCICO. Thus, the actual credits that can be applied to future years would be less than the 525,000 credits indicated.

technology-such as installation of alternative fuel infrastructure or alternative fuel production facilities.

As noted in the scenario results discussion, the generation of additional credits in early years, to allow for potential shortfalls as potential technical or market barriers are overcome, could be a reasonable approach to provide some safeguards towards future CI deficit years. With the inherent possibility that forecasted fuel projections may be higher or lower, regulated parties should consider taking early actions to ensure compliance with the required reductions.

Regulated parties may also be able to expand their compliance options by producing lower carbon alternative fuels, or buying credits from others that market such fuels. As regulated parties determine how compliance will be achieved, the introduction of new technology, low CI fuels, and blendstocks in the market will provide for stable and effective compliance options. Use of these options may provide regulated parties with more flexibility in achieving compliance.

Since the vast majority of the compliance obligation is being incurred by entities that market both gasoline and diesel, interchangeable use of gasoline and diesel credits is expected to be used to achieve compliance. While there may be excess credits generated using gasoline fuels through the use of ethanol blends, higher blends of non-conventional diesel may progress and become credit generators in the mid-term of the program.

To the extent possible, investment towards commercialization of new and advanced production and blending technology could pay dividends if technology advancement leads to efficient and more cost-effective means of fuels production and marketing.

2. Challenges to Meeting the Targets

As discussed above, staff, as well as several panelists, believes that the analysis above shows that near and mid-term targets are achievable under a variety of conditions. This conclusion is supported by the substantial generation of credits to date and by illustrative scenarios done by ARB staff, which show there are numerous scenarios in which mid-term targets could be met with lower carbon fuels that are currently available. Not included in the scenario analysis is the potential for California low carbon biofuel production. The California Energy Commission has provided $45 million in incentives as co-funding matched by $64 million from private investors and other sources for pre-development stages of seventeen projects throughout the state. These projects could displace 95 million to 525 million GGE of petroleum by 2020 dependent on various capacity levels of commercialization of the fuel production plants. These projects are expected to be in commercial operation between 2016 to 2020.[87] Certain stakeholders have expressed concerns with the adequacy of new generation fuels assumed to be available to fully meet the 2020 goals of the LCFS and the RFS2. With regard to the

[87] California Energy Commission, Benefits Report for the Alternative and Renewable Fuel and Vehicle Technology Program for the 2011 Integrated Energy Policy Report, December 2011.

longer-term targets, staff believes that it is too early in the program's implementation to identify with certainty the strategies regulated parties would likely use to meet those targets. Nonetheless, staff believes that the illustrative scenarios show that there are approaches and combinations of fuel technologies that could be used to achieve the long-term targets, and that there is sufficient time to develop the needed production capacities for these fuels. However, some panelists have presented their opinion that the targets are not feasible, they suggest that a lack of progress on commercialization of large volumes of low CI fuel lend credence to these views.

The LCFS is a "back-loaded" performance standard that is designed to require only modest CI reductions in the near and mid-term. The LCFS is designed this way to provide sufficient time and investments for advanced fuel technologies, many of which exist today in limited quantities, to become fully commercialized in time to meet the more stringent standards in the 2018-2020 timeframe. Some of the fuel technologies that may be used to meet the targets have some challenges to commercialization. Because the Panel was interested in discussing this topic, staff worked with panelists to identify some of these challenges.

A potential challenge to meeting the targets fully is if all fuels that are expected to help achieve compliance are in short supply for extended periods. For example, production volumes for lower-CI ethanol, biodiesel, and drop-in fuels may not be high enough to meet the targets. If the vehicle population increases, the shift to alternative fuels such as natural gas, electricity and hydrogen, substantially more credits could be generated than anticipated. Staff notes, however, that for the near and mid-term horizon, production capacity for lower-CI ethanol and biodiesel appears to be ample for meeting California's needs.

Another potential challenge would be the shortage of feedstocks needed for the production of low CI fuels. If there is substantial competition amongst states for feedstocks, or if substantial quantities of biofuel feedstocks are redirected towards food production for any reason, fuel use may need to be re-evaluated to determine if adjustments to the illustrative scenarios are needed. A full discussion of these challenges is beyond the scope of this chapter; Chapter V discusses more extensively these and other possible challenges for specific fuels.

If the costs of supplying the appropriate CI fuels to the vehicle population are higher than anticipated, people may defer to lower-cost options with higher CIs. A full discussion of economic challenges is beyond the scope of this chapter; Chapter VII discusses the economic challenges more extensively.

D. Potential Flexible Compliance Mechanisms

1. Staff's Perspective on the Need for Flexible Compliance Mechanisms

In addition to discussing challenges, some panelists were interested in discussing whether a flexible compliance mechanism was appropriate for inclusion in the regulation. It was suggested that ARB consider a flexible compliance mechanism for use in case a regulated party may not able to meet the compliance target in a given compliance period despite its good faith efforts to do so. Staff agreed to take a closer look into such a mechanism as part of this review and make a preliminary determination if such an option has merit sufficient to warrant further investigation for possible inclusion within the LCFS program. Staff asked interested panelists to prepare a separate analysis to identify the elements of what the panelists believe are appropriate flexible compliance mechanisms. The main elements of the analysis are discussed later in this chapter.

As suggested, the concept is not intended as a substitute for the overall LCFS compliance schedules (i.e., so that regulated parties would have a choice between complying with the LCFS standards or the flexible compliance mechanism at any given time). Instead, the suggested concept of a flexible compliance mechanism would only come into play if specified adverse market conditions occur. The concept would provide a given regulated party a short-term alternative with which to comply assuming they can demonstrate compliance difficulties due to adverse market conditions. One such set of circumstances could occur if the credit market is short at some point in the program (e.g., if regulated parties hold onto their credits rather than trade them en masse); several panelists suggested a flexible compliance mechanism that might, for example, be set up to enable ARB to provide sufficient credits to the market to equalize such market perturbations.[88]

Staff continue to see indications that the LCFS standards are feasible and achievable. For example, based on data in the LRT, there are substantially more credits in the market currently than there are deficits. Staff's analysis of the first three quarters of 2011 data shows that there are about 450,000 MT of CO_2e "net" credits (more credits than deficits generated) registered in the LRT. Further, staff's preliminary analysis of second and third quarter 2011 data suggests that the number of net credits has increased significantly relative to the first quarter. The increase of net credits is an indication that there are companies on track to meet or exceed their compliance obligations. However, staff is open to continue discussing the concept of a flexible compliance mechanism with stakeholders in an effort to determine if it might be an appropriate amendment at some point in the future.

[88] One example suggested by panelist Bob Epstein (E2) and others, citing a recent example in the state of Hawaii, would involve the State of California receiving LCFS credits through a contract to supply the State's vehicular fleet with lower-CI fuels. A potential use of such credits would be for strategic easing of credit market fluctuations at pre-determined credit prices.

Market responses further in the future become more difficult for market participants to predict. Enhancing the LCFS with a flexible compliance mechanism could reduce some uncertainties thereby increasing investor confidence. Greater clarity regarding future market demand should accelerate private sector development of low carbon fuel options, thereby expanding market options for regulated parties and creating competition to supply consumers with the best, and least expensive, options.

Therefore, staff have made a determination that such an option has merit sufficient to warrant further investigation for possible inclusion within the LCFS program. Given the lead times that may be required to commercialize additional supply of low carbon fuel, this work should be undertaken as quickly as feasible. Therefore, after the Board hearing in December 2011, staff anticipates following up with stakeholders in early 2012 to further investigate the feasibility of developing the concept of a flexible compliance mechanism.

2. Panelists' Perspectives on the Need for Flexible Compliance Mechanisms

A diverse group of Advisory Panel members expressed interest in exploring options for enhancing the LCFS with a flexible compliance mechanism and responding to the Staff request for an analysis of such an option. That group discussed various ways that a flexible compliance mechanism might be structured. Panelists identified potential benefits of a flexible compliance mechanism, as well as additional questions needing further consideration.

The panel had a robust discussion of possible flexible compliance mechanisms and the result was that a majority of panelists were supportive of the concept. Panelists indicated that it could be useful not only to help regulated parties comply when unforeseen events occur, but also to provide regulatory certainty to the LCFS since there would be a defined method of handling unforeseen events. The panel convened an independent group that met with staff to discuss initial questions regarding the goals and design objectives of any flexible compliance mechanism.

Predicting the market availability and rate of deployment of low carbon fuels is difficult at this early stage of the LCFS compliance schedule. As regulated parties consider economic tradeoffs, the market will begin its transition to lower CI fuels. As such, the market may experience temporary periods when demand for low carbon fuels exceeds supply. This imbalance may then lead to temporary shortfalls which may hamper the ability of regulated parties to comply with the LCFS targets. For example, regulated parties may not be able to procure either enough fuel or credits to comply based on factors outside that parties control such as supply disruption or possibly credit hoarding or other unforeseen events. Because of these possible shortfalls, flexible compliance mechanisms may need to be considered in order to maintain market stability and reduce the risk of high LCFS credit prices.

Developing fuel markets are inherently uncertain. Therefore, developing a flexible compliance mechanism that can reduce risks to regulated parties may increase market confidence and encourage investment. In some cases, the presence of a flexible compliance mechanism could also provide valuable information about LCFS credits that may help give investors the confidence to invest in the market. This is because in the relatively challenging program period from 2017 to 2020, one might expect that the value of credits would tend towards the cost of flexible compliance. Many of the panelists have expressed support for flexible compliance mechanisms, however some panelists are opposed to the idea.

Ideally, any flexible compliance mechanism would be long-term, transparent and predictable. A flexible compliance mechanism addresses how the program will operate in the event that an obligated party does not meet its obligation with market-sourced fuels or credits. A well-designed flexible compliance mechanism should:

- Be fair to parties that successfully comply with their obligation under the LCFS as well as to parties that temporarily cannot comply due to the limited availability of credits or low-carbon fuels.
- Ensure the stability of the LCFS program as the market expansion of available low-carbon fuels proceeds.
- Provide a clear, dependable signal to obligated parties and potential low-carbon fuel investors about how ARB would act in the event of a credit or supply shortfall so that parties can make efficient long-term investment decisions.

E. Summary and Conclusions

The LCFS is in the initial stage of implementation, and only data for the first six months have been reported under the LCFS reporting tool. The data that have been reported to date strongly suggest that regulated parties are able to meet the targets at this point. The reported data also indicate that almost twice as many credits are being generated than are being expended. The information presented in this chapter, including analysis of the illustrative scenario results, suggests that many potentially viable paths exist to attain compliance with the carbon intensity standards through 2020, and that compliance through the midterm years (2011 through at least 2015) is possible with anticipated improvements of the CI of alternative fuels that are currently available. The actual fuel mix that regulated parties would use is difficult to predict. But, the scenarios show that various means exist to meet compliance.

Panel discussions around regulated parties and the targets of the LCFS were robust and included not only a discussion of what activity has been reported thus far, but the state of both new technologies and investments in those technologies. With the variety of panelists participating in the conversation, many different viewpoints were heard. Traditional fuel providers generally expressed belief that there were not enough low carbon fuels available to meet mid to long term goals, while biofuel providers generally expressed belief that there was opportunity to generate credits using fuels that are currently available, especially if the use of these fuels is expanded. There were also several panel members who provide fuels that are banking credits in the system.

A majority of panelists have suggested that ARB evaluate a flexible compliance mechanism for regulated parties in the event that they may not be able to meet the targets due to a potential temporary future shortage in credits or supply of complying fuels. Staff agreed to take a closer look into such a mechanism as part of this review and have made a determination that such an option has merit sufficient to warrant further investigation for possible inclusion within the LCFS program.

Given the lead times that may be required to commercialize additional supply of low carbon fuel, this work should be undertaken as quickly as feasible. Therefore, staff anticipates following up with stakeholders in early 2012 to further investigate the feasibility of developing the concept of a secondary compliance mechanism.

One of the goals for the upcoming December 2011 rulemaking is to help make credits more accessible in the marketplace. The upcoming proposed amendments would help establish a favorable market-trading framework that, in turn, should help make these credits more accessible for purchase by regulated parties who may need such credits to meet their obligations.

VII. Economic Assessment

In this chapter, staff provides an update to the economic analysis conducted in support of the original 2009 LCFS rulemaking. As in the original analysis, this update compares the estimated costs of producing petroleum-based transportation fuels with corresponding cost estimates for alternative fuels. For a full discussion of the assumptions and methodologies used in the original economic analysis, please refer to the 2009 LCFS Initial Statement of Reasons.[89]

This analysis does not attempt to account for carbon-intensity-based price effects. Having examined existing fuel price data, staff has concluded that sufficient information on which such an accounting could be based does not yet exist. ARB staff will continue to work with the California Energy Commission (CEC) and other interested stakeholders to refine the LCFS economic analysis so that it accounts for carbon intensity effects, the termination of tax subsidy and tariff programs, and other factors.

A. Summary of the Economic Impacts

The analysis that follows is based on estimated costs of producing the transportation fuels that are likely to be in use in California during the term of the LCFS regulation. Staff prepared estimates for both petroleum-based fuels—gasoline and diesel—and for the lower-CI fuels that will be used in combination with petroleum fuels to achieve compliance with the LCFS. Staff then applied these estimated costs to the gasoline and diesel illustrative scenarios appearing in Chapter VI of this staff report. Each of these scenarios describes a mix of transportation fuels that would satisfy the LCFS carbon intensity (CI) reduction targets each year through 2020. The lower-CI fuels included in the illustrative scenarios are liquid fuels, such as ethanol and biodiesel, and several non-liquid fuels: electricity, hydrogen, and compressed natural gas (CNG). As staff moves forward with additional analyses, it will also consider the use of liquefied natural gas (LNG) as a transportation fuel.

Staff considered all transportation fuel production and distribution costs in its analysis. In the case of ethanol, these costs were adjusted to reflect the expectation that the federal Renewable Fuel Standard (RFS2) would bring significant quantities of ethanol into California. Therefore, the infrastructure costs associated with moving ethanol from its point of production into motor vehicle fuel tanks are attributed to the federal program for those ethanol volumes that satisfy both the federal and state programs. These infrastructure costs include the facilities and equipment used for transportation, storage, and dispensing. Although "advanced" and cellulosic fuels will be produced to meet RFS2 requirements, staff attributed the production costs of these biofuels to the LCFS, since the State program will have to attract biofuels with a lower CI than the national

[89] Air Resources Board, March 5, 2009, Proposed Regulation to Implement the Low Carbon Fuel Standard. Volume I Staff Report: Initial Statement of Reasons. Chapter VIII, Economic Impacts. http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf.

average in order to achieve its fuel CI reduction targets. With this assumption, staff is being conservative, as certainly more of these advanced fuels will be produced to meet RFS2—the LCFS merely attracting more than a proportional share to California.

Production cost estimates such as those presented in this analysis are necessarily based on assumptions about future economic conditions. To the extent that staff's assumptions are consistent with actual future conditions, the cost estimates based on those assumptions should be reasonably close to actual costs. Conversely, if actual conditions diverge from staff's assumptions, actual costs will also diverge from the estimates presented below. Staff's estimates will be sensitive to assumptions about oil prices, about the timing of the entry of lower-CI fuels into the market, and the general condition of the American and world economies.

The fuel production cost impacts of the LCFS are assessed in this chapter by comparing the estimated per-gallon fuel costs for all scenarios in all years (2011-2020) with estimated baseline costs. Baseline costs reflect the "business-as-usual" conditions that would have been in place in the absence of the LCFS, but include fuels that would be made available on the California market by the federal RFS2. Because the illustrative scenarios on which these comparisons are based attempt to capture reasonably foreseeable variations in the future California transportation fuel mix, the cost analysis based on those scenarios is likely to bracket actual future cost effects.

The results presented below suggest that the estimated production costs of gasoline substitute fuels may have little impact on the cost of the LCFS program, but the production costs of alternative diesel fuels could increase costs to the LCFS in the later years of the regulation. As stated earlier, this cost-of-production analysis does not take into account the carbon-intensity-based market price effects, the magnitude of which is unknown and difficult to predict, but will be the subject of continuing economic analysis.

B. Key Revisions to 2009 Economic Analysis

Table VII-1 summarizes the significant differences between the current analysis and the analysis completed for the 2009 Initial Statement of Reasons (see footnote 1, above).

Table VII-1: Differences between the 2009 and the Current LCFS Economic Analyses

2009	2011
Excluded costs borne by RFS2	Uses RFS2 as baseline case
Included biofuel tax subsidies and ethanol import tariffs	Biofuel tax subsidies and ethanol import tariffs are not included
Used U.S EPA cellulosic fuel projections	Uses EIA cellulosic fuel projections
Varied number of EVs and FCVs *among* scenarios	Held number of EVs and FCVs constant among scenarios
No LCFS credits used for compliance	LCFS credits used for compliance

Because RFS2 is in effect regardless of the LCFS, the cost of the additional ethanol infrastructure required to comply with both RFS2 and LCFS programs was attributed to RFS2 in this analysis. Staff observed in 2009, however, that California's proportional share (~11 percent) of the mandated RFS2 ethanol volumes would be sufficient to satisfy the State's ethanol needs under the LCFS, although the CI of the ethanol generally needed for LCFS compliance would be lower than the average CI of the ethanol typically produced under RFS2.

Ethanol infrastructure remains categorized as an RFS2 cost in the current analysis. Rather than subtracting off infrastructure costs, however, these costs are included in the baseline scenario. This analysis attributes to the LCFS any differential between baseline scenario costs and "with LCFS" scenario costs. LCFS costs, in other words, consist of "with LCFS" costs minus "without LCFS" (baseline) costs. Including RFS2-related infrastructure costs in the baseline, therefore, assures that they are not attributed to the LCFS.

The 2009 analysis assumed that the federal ethanol and biodiesel tax subsidy program would continue to be extended as it had been in the past. Tariffs on ethanol imports[90] were also assumed to remain in place. Recent deficit-reduction measures, however, have targeted both subsidies and tariffs for termination. Accordingly, neither subsidies nor tariffs are included in the current economic analysis.

The creation of the illustrative scenarios appearing in Chapter VI was driven largely by a significant scaling back of projections for the production of cellulosic ethanol. The U.S. Energy Information Administration (EIA) is currently forecasting production volumes well below the volumes assumed by the U.S. Environmental Protection Agency (EPA) in its RFS2 Regulatory Impact Analysis.[91] The volumes used in the current illustrative scenarios are derived from the EIA's current cellulosic ethanol projections.[92]

Sufficient volumes of cellulosic ethanol were assumed in the 2009 scenarios to make the use of banked or acquired (i.e., excess) credits unnecessary in meeting annual CI limits. This approach was necessarily reversed in the current analysis: only very modest quantities of cellulosic ethanol are projected, making it necessary for regulated parties to use excess credits to achieve compliance in the later years of the regulation. As discussed in Chapter VI, regulated parties are currently generating a substantial number of excess credits (i.e., more credits than necessary to meet compliance requirements in 2011), so the application of credits for compliance in later years is reasonable and expected.

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[90] Imports from countries not within the Caribbean Basin Initiative were subject to tariffs.
[91] Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. February 2010. Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis. EPA-420-R-10-006.
[92] U.S. Energy Information Administration, Annual Energy Outlook 2011: with Projections to 2035, April 2011, Total Energy Supply, Disposition, and Price Summary Table

Finally, in its 2009 analysis, staff varied the number of ZEVs among the scenarios from 500,000 to 2 million in order to bracket the likely range of ZEV penetration over the course of the LCFS regulation. For the current analysis, however, staff used its best estimate of ZEV penetration from 2011-2020 and held that number constant among the gasoline scenarios. (See Chapter VI for a full explanation of the scenarios.) The 2009 ZEV estimates were "what if" scenarios—what if there were one million or two million ZEVs on the road?—whereas the 2011 analysis concentrated more on the array of alternative biofuels that could be used for compliance, given some estimated penetration of ZEVs. Since the driving issue of the 2011 analysis was availability of fuels, staff believed that holding the ZEV penetration constant among illustrative scenarios would focus more on biofuel availability and use. Regardless of the approach, the LCFS does not mandate the use of alternative-fueled vehicles, as it does not mandate the use of any specific alternative fuel.

C. Estimated Costs Of Fuel Production

This section presents cost estimates for the production of both petroleum-based fuels—gasoline and diesel—and for the lower-CI fuels that will be used in combination with petroleum fuels to achieve compliance with the LCFS. The lower-CI fuels included in the analysis are liquid fuels such as ethanol and biodiesel, and several non-liquid fuels: electricity, hydrogen, and compressed natural gas (CNG). The cost estimates for all fuels include the capital costs for building new fuel production facilities, the costs of operating those facilities, and the costs of distributing the fuels produced.

1. Gasoline and Diesel Costs

The crude oil and petroleum fuel cost estimates used in this analysis consist of wholesale prices developed by the California Energy Commission (CEC) as part of its 2011 Integrated Energy Policy Report (IEPR).[93] Although wholesale prices are slightly higher than production costs, the components that are unrelated to production costs (i.e., refinery profit) vary for individual refiners and temporally for the industry as a whole and therefore cannot easily be isolated and removed. For this analysis, staff averaged the low- and high-demand crude prices from the IEPR.

[93] CEC, Transportation Energy Forecasts and Analyses tor the 2011 Integrated Energy Report: Draft Staff Report, 2011. Sacramento, CA.: CEC-600-2011-007-SD. Staff used wholesale prices appearing in a spreadsheet posted for the November 14, 2011 public workshop. It is available at http://www.energy.ca.gov/2011_energypolicy/documents/index.html#11142011. The prices reported exclude federal, state, and local taxes.

Table VII-1
Estimated Crude Prices and Associated Costs to Produce and Distribute Gasoline and Diesel[a]

Year	Crude Price ($/bbl)	Cost of CARBOB Production and Distribution ($/gal)	Cost of Diesel Production and Distribution ($/gal)
2011	$97.3	$2.59	$2.78
2012	$103.1	$2.62	$2.74
2013	$106.5	$2.70	$2.82
2014	$110.1	$2.78	$2.90
2015	$112.8	$2.84	$2.97
2016	$113.2	$2.85	$2.97
2017	$113.4	$2.86	$2.98
2018	$113.5	$2.86	$2.98
2019	$113.3	$2.86	$2.98
2020	$113.1	$2.85	$2.97

[a]The prices in this table are derived from wholesale prices developed by the California Energy Commission. Please see http://www.energy.ca.gov/2011_energypolicy/documents/index.html#11142011. These prices are averages of CEC's high and low demand scenario prices which can be found in a spreadsheet posted for the CEC's November 14, 2011 public workshop. The prices reported exclude federal, state, and local taxes. Crude oil prices are in real 2010 dollars and are included in Table B-1, Appendix B, of the 2011 IEPR. See footnote 5 to this document for a full reference.

2. Lower-CI Fuel Production and Distribution Costs

a. General Discussion

This section presents production and distribution costs for the lower-CI fuels included in the LCFS illustrative scenarios (see Chapter VI). The overall carbon intensity of the California transportation fuel supply will decline as these fuels displace traditional petroleum-based fuels. This group of lower-CI fuels includes both liquid biofuels (ethanol and biodiesel) and non-liquid fuels (hydrogen, electricity, and CNG).

Lower-CI Liquid Biofuels

The liquid biofuel production and distribution cost estimates presented in this section include capital costs for the construction of production facilities; fuel production costs; feedstock acquisition costs; and storage, transport, and distribution costs. Each of these cost categories is discussed individually below. Staff adjusted its cost estimates, where applicable, to account for the sale of products that are co-produced along with some liquid biofuels: livestock feed, raw materials for other products, captured or co-generated energy that can be used in the plant or exported as electrical energy, etc.

While some liquid biofuels are currently available on the market—corn and sugarcane ethanol, and biodiesel from crops, animal fats, and grease—other lower-CI liquid fuels are at an earlier stage of development. Cellulosic ethanol and hydrocarbons from green waste, for example, have yet to enter the market in significant quantities.

So that all gasoline and gasoline-replacement fuel costs reported in the analysis are directly comparable, cost figures for gasoline-replacement fuels are expressed in terms of gasoline-gallon-equivalents (GGEs). This conversion enables all unit costs to refer to an equivalent quantity of fuel energy—the amount contained in one gallon of gasoline.[94] Biodiesel and renewable diesel fuels required no such conversion because they contain almost the same amount of energy on a per-unit volume basis as petroleum fuels. CNG costs, however, are expressed in terms of diesel-gallon-equivalents (DGEs).[95] Electricity used in medium- and heavy-duty electric-powered trucks is also converted to DGEs.

<u>Other Lower-CI Fuels:</u>

In addition to liquid biofuels, staff estimated the cost of producing and distributing three other lower-CI fuels: hydrogen, [96] electricity, and CNG. As with the liquid biofuels, staff converted these costs to petroleum-fuel-equivalent energy values—GGEs in the case of hydrogen and electricity used in light-duty vehicles and DGEs in the case of CNG and electricity used in medium- and heavy-duty vehicles.

Because these non-liquid fuels are used in vehicles with unconventional drivetrains, a further adjustment is also necessary. In order to account for the differences in efficiency between these unconventional drivetrains and their more conventional counterparts, the LCFS regulation assigns each unconventional drivetrain system an energy economy ratio (EER). EERs are unitless efficiency factors: since electricity-powered vehicles are 3 times as efficient as conventional gasoline-powered vehicles, for example, the electricity EER is 3.0. The EERS for the other two fuels covered in this section are 2.3 for hydrogen, and 0.9 for CNG used as a diesel substitute fuel. In this analysis, staff adjusted production costs for drivetrain efficiency by simply dividing the GGE- or DGE-based production cost by the EER. For example, an electricity cost of $0.09 per kilowatt-hour (kW-hr) converts to $2.89 per GGE. The EER-adjusted GGE value, therefore, would be $2.89 divided by three, or $0.96 per GGE.

b. Capital Costs

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94 $$GGE\ for\ ethanol = Cost\left(\frac{\$}{gal}\right) X \frac{\left(109{,}600\,\frac{\text{btu}}{\text{gal}}\,\text{for gasoline}\right)}{\left(76{,}330\,\frac{\text{btu}}{\text{gal}}\,\text{for ethanol}\right)}$$

95 $$DGE\ for\ CNG = GGE\ Cost\ of\ CNG\left(\frac{\$}{gal}\right) X \frac{\left(127{,}464\,\frac{\text{btu}}{\text{gal}}\,\text{for diesel}\right)}{\left(109{,}600\,\frac{\text{btu}}{\text{gal}}\,\text{for gasoline}\right)}.$$

96 Senate Bill 1505 (Lowenthal, 2006) directed the ARB to develop a regulation to set environmental standards for hydrogen fuel produced and dispensed for transportation use in California. As this bill demonstrates, hydrogen production costs can be affected by legislation and regulation.

Alternative fuel capital costs developed for the 2009 analysis are incorporated without change into the current analysis. Staff found no evidence of significant changes in these costs between 2009 and the present. The diesel illustrative scenarios on which the current analysis is based, however, contain three fuels that were not included in the 2009 analysis: canola and corn oil biodiesel, and tallow renewable diesel. These new biodiesel fuels were assumed to have the same capital cost structure as the biodiesel fuels that were included in the 2009 analysis.

c. Production Costs

The costs to produce the biofuels include fixed and variable costs. Fixed costs include taxes, interest, baseline utilities, and insurance, while variable costs include non-baseline utilities, labor and other operating and maintenance costs, non-feedstock raw materials (sulfuric acid, lime, nutrients, etc.), and waste disposal. Based on analyses conducted by NREL[97] and Haas,[98] 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. Staff used the same production costs in 2011 as in 2009, with the exception of CNG.

Staff estimated CNG production costs by subtracting excise and sales tax amounts from the CEC's retail price estimates.[99] According to the CEC, the average retail price of CNG (the average CEC's high- and low-demand cases) is estimated to fall between $2.95 and $3.01/GGE over the 2011–2020 compliance periods. Staff subtracted the sales tax and the excise taxes from CEC's price estimates to derive its cost estimates. The result is an EER-adjusted cost range of $2.19 to $2.24/GGE. These values were converted to DGEs in the diesel scenario calculations.

d. Feedstock Costs

Per gallon feedstock costs for ethanol production are calculated as follows:

Feedstock Cost per Gallon = Cost of Feedstock/ Ethanol Yield from Feedstock

For example, if the cost of corn is $5.18 per bushel and the dry-mill ethanol yield is 2.72 gallons of ethanol per bushel, then the feedstock cost is $1.90/gal, or $2.72/GGE.

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[97] Andrew McAloon and et al. (2000). Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks. National Renewable Energy Laboratory.
[98] Michael J. Haas and et al. (2006). "A process model to estimate biodiesel production costs." Bioresource Technology 97: 671-678.
[99] CEC, Transportation Energy Forecasts and Analyses for The 2011 Integrated Energy Report: Draft Staff Report, 2011. Sacramento, CA.: CEC-600-2011-007-SD. The CNG retail prices used are from Table B-6 (Appendix B, page B-10), The tax amounts that were subtracted off are from Table B-5, page B-9 of the same document. .

Calculated ethanol feedstock costs varied between \$0.43/GGE and \$2.83/GGE, with sugarcane being the least expensive and corn for a wet-mill plant being the most expensive.

Based on information developed by the U.S. EPA for the RFS2, staff estimated the cost of municipal solid waste (MSW) as a feedstock at \$35/ton.[100] The specific waste streams included in this analysis are the yard waste, wood, and paper components of the total municipal solid waste stream. Although MSW could be assumed to be a costless or even a negative cost feedstock (due to avoided tipping fees and the generation of electricity for export from captured landfill gas), staff assumed that the cost of sorting the waste stream partially offsets these cost-reducing factors.

Staff estimated bio- and renewable diesel feedstock costs to range between \$2.85/gal and \$4.21/gal (see Table VII-3, below). The lowest-cost bio- and renewable diesel feedstock is used cooking oil. The highest-cost feedstock is canola oil. Both are used to produce fatty acid methyl ester (FAME) biodiesel and renewable diesel.

Like fuel production costs, feedstock costs are influenced by the cost of crude oil. About 20 to 35 percent of the cost of cultivating corn or soybeans is directly attributable to fuel and petrochemical costs.[101] These costs include field equipment fuel (diesel and gasoline), fertilizer, electricity, and transportation fuel costs. Labor, most nonpetroleum chemicals, and capital recovery costs for machinery are not affected by crude prices. To be conservative, staff increased liquid biofuel feedstock costs by 35 percent of the percentage increase in crude oil prices.

The feedstock cost estimates reported in this analysis include transport costs. Staff assumed that feedstocks are transported 50 miles from their origination points to fuel production facilities.

Although hydrogen can be produced from natural gas, biogas, biomass, coal, or water, the hydrogen feedstock costs reported in this analysis are based on the use of what is currently the most common feedstock: natural gas. The costs of hydrogen feedstocks vary considerably, but the costs of converting them to hydrogen are also quite variable. Converting natural gas to hydrogen via steam-methane reformation (SMR) is currently the most common and generally least expensive process. Biogas from landfills and anaerobic digesters can also be used as an SMR input. Coal and wood wastes can also be gasified and the resulting gas used as an SMR input, but this is a relatively energy-intensive and costly process. Converting water to hydrogen via hydrolysis is also energy-intensive and costly, but these costs—as well as the CI of the process—can be reduced if renewable energy sources such and wind and solar power are used. Staff estimated the EER-adjusted cost of what is currently the most commonly-used feedstock, natural gas, to be \$0.70/GGE (see Table VII-3, below).

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[100] Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. April 2007. Regulatory Impact Analysis: Renewable Fuel Standard Program. EPA420-R-07-004.
[101] 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.

Table VII-3 summarizes the commodity prices and yields that staff used to determine the per-gallon feedstock costs for the liquid alternative transportation fuels considered in this analysis. All the prices have changed significantly since the 2009 ISOR. To give some examples, corn prices have increased from $3.77/bushel to $5.18/bushel; soybean oil prices from $0.34/lb. to $0.51/lb., while yellow grease has gone from $0.11/lb. to $0.36/lb.

Table VII-3
Commodity Prices (2011 Dollars) and Yields

Commodity	Price	Reference	Yield	Reference
Corn (dry mill)	$5.18/bu	USDA ERS[a]	2.72 gal/bu	CA-GREET, 2009 [h]
Corn (wet mill)	$5.18/bu	USDA ERS[a]	2.62 gal/bu	CA-GREET, 2009 [h]
Corn Stover	$90/ton	RFS RIA[b]	80.6 gal/ton	Antares, 2008 [i]
Wood Chips (Cellulosic)	$75/ton	NREL, 2008[c]	90.2 gal/ton	Antares, 2008 [i]
Wood Chips (FT)	$75/ton	NREL, 2008 [c]	42 gal/ton	Antares, 2008 [i]
Soybean Oil (FAME)	$0.51/lb	CBOT, 2009 [d]	1.0 gal BD/gal oil	Calculated from CA-GREET, 2009 [h]
Yellow Grease, UCO (FAME)	$0.36/lb	Tribe, 2008[e]	249 gal/ton	Antares, 2008 [i]
Canola Oil (FAME)	$0.55/lb	Canola Council of Canada[f]	1.0 gal BD/gal oil	Calculated from CA-GREET, 2009 [h]
Corn Oil (FAME)	$0.54/lb	USDA AMS[g]	1.0 gal BD/gal oil	Calculated from CA-GREET, 2009 [h]
Renewable Diesel (Tallow)	$0.45/lb	USDA AMS[j]	250 gal/ton	Antares, 2008 [i]
Yellow Grease (FAHC)	$0.36/lb	Tribe, 2008 [e]	250 gal/ton	Antares, 2008 [i]
Municipal Solid Waste (vegetation and paper)	$35/ton	Based on RFS RIA[b]	86 gal/ton – paper 70 gal/ton - vegetation	Antares, 2008 [i]

[a] Capehart, Tom and Edward Allen, United States Department of Agriculture, Economic Research Service, November 14, 2011. "Feed Outlook. U.S. Feed Grain Production Lowered for 2011/2012. FDS-11k. http://usda01.library.cornell.edu/usda/current/FDS/FDS-11-14-2011.pdf. Table 1 on page 16 gives a 2010/2011 market year price of $5.18 per bushel.
[b] Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. April 2007. Regulatory Impact Analysis: Renewable Fuel Standard Program. EPA420-R-07-004.
[c] NREL (2008). Wood Chips to Heat Laboratories, Save Natural Gas. National Renewable Energy Laboratory
[d] CBOT. (2009). "CBOT Soybean Oil (ZL, ECBOT)." Retrieved, from http://www.tfc-charts.w2d.com/printchart/ZL/C9.
[e] Forum post to Tribe. November 27, 2008. "WVO Yellow Grease price drops." Retrieved, from http://biodiesel.tribe.net/thread/12d12d00-d509-435e-b341-fa459b38decb.
[f] Canola Council of Canada. November 8, 2011. Seed, Oil and Meal Prices. http://www.canolacouncil.org/canolaprices.aspx.
[g] United States Department of Agriculture, Agricultural Marketing Service. November 29, 2011. USDA-MO Dept. Ag Market News. Corn Belt Feedstuffs. http://www.ams.usda.gof/mnreports/sj_gr225.txt.

[h] ARB (2008). California-GREET Model version 1.8b. Air Resources Board. http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.
[i] Antares Group, July 15, 2008. Strategic Assessment of Bioenergy Development in the West. Task 2: Bioenergy Conversion Technology Characteristics FINAL REPORT. Prepared for the Western Governors' Association. Canola biodiesel costs based on soy biodiesel costs.
[j] United States Department of Agriculture, Agricultural Marketing Service.

e. Cost Credit for Additional Products

The production of some biofuels generates co-products which have market value. Dry-mill corn ethanol plants, for example, co-produce a valuable livestock feed known as distiller's grains with solubles (DGS). These are the solids that remain after the fermentation and distillation processes are completed. DGS is used as a partial substitute for feed corn and, in some cases, soy meal.

DGS prices vary with prices of the feeds for which they substitute. According to the CA-GREET model, a bushel of corn produces 2.72 gallons of ethanol and 14.5 pounds of dry DGS. Corn is currently priced at $5.18/bushel while dry DGS is selling for about $195/ton[102]. Staff had an estimate of $3.58/bushel and $150/ton in 2009 ISOR, respectively. Staff calculated co-product cost credits based on the cost estimates appearing in Table VII-4.

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[102] This Corn price is from Capehart, Tom and Edward Allen, United States Department of Agriculture, Economic Research Service, November 14, 2011. "Feed Outlook. U.S. Feed Grain Production Lowered for 2011/2012. FDS-11k. http://usda01.library.cornell.edu/usda/current/FDS/FDS-11-14-2011.pdf. Table 1 on page 16 gives a 2010/2011 market year price of $5.18 per bushel. The dry DGS price is from United States Department of Agriculture, Agricultural Marketing Service, December 2, 2011. "National Weekly Distillers Grains Summary, USDA Livestock and Grain Market News." Des Moines, Iowa. http://www.ams.usda.gov/mnreports/lswndgs.pdf. This source present weekly average DGS price data, but also graphs prices for the previous year. Prices for the current and the previous two years. 2011 Iowa DDGS prices (FOB plant) have averaged about $195/ton

Table VII-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[a]
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[b]
Lignocellulosic Fermentation	Corn Stover Wood Chips MSW (Grass, Wood, and Paper)	Electricity	Varies	Wholesale price estimated at $0.054/kW-hr[c]
Fischer-Tropsch Diesel	Wood Chips	Electricity Naphtha	Varies 30% liquid yield	$0.054/kW-hr[c] $1.50/gal[d]
FAME Biodiesel	Soybean oil, UCO, Canola, Corn Oil	Glycerin	7% of feedstock	$0.32/gal[e]
FAHC Diesel	Tallow	Light Hydrocarbons	3.5 – 4.4 wt % of feedstock	$1.04/gal[d]

[a] CNN. (2009). "Commodities Pricing." Retrieved, from http://money.cnn.com/data/commodities/.
[b] Sparks Companies (2002). Corn Based Ethanol Costs and Margins. Kansas State University
[c] Estimated by ARB staff based on a retail price of $0.09/kW-hr, as discussed elsewhere in this Chapter
[d] Antares Group, July 15, 2008. Strategic Assessment of Bioenergy Development in the West. Task 2: Bioenergy Conversion Technology Characteristics FINAL REPORT. Prepared for the Western Governors' Association.
[e]ICIS. May 18, 2011. "18 May 2011 Glycerine (US Gulf)." http://www.icispricing.com/il_shared/Samples/SubPage170.asp

f. Storage, Transport, and Distribution Costs

In 2009, staff used U.S. EPA's Renewable Fuel Standard (i.e., RFS1) regulatory impact analysis to estimate biofuel storage, transport, and distribution costs.[103] Staff estimated the cost for storage, transport, and distribution of out-of-state ethanol to be $0.23/gal, or $0.34/GGE for ethanol. According to a California biofuel production facility,[104] the cost to transport ethanol within California (Northern California to Southern California) by truck is between $0.20/gal and $0.30 per gallon. Because estimates are almost equal, staff used the same cost for storage, transport, and distribution for ethanol produced both in- and out-of-state.

[103] Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. April 2007. Regulatory Impact Analysis: Renewable Fuel Standard Program. EPA420-R-07-004.
[104] Personal communication, Darren Knop, Pacific Ethanol, 2009. Ethanol Freight costs.

As part of this analysis, staff reviewed U.S. EPA's current RFS2 Regulatory Impact Analysis, which updated the original 2007 study.[105] Because the Environmental Protection Agency used the same storage, transport, and distribution costs as it did for the original Regulatory Impact Analysis, staff made no revisions to its 2009 storage, transport, and distribution cost estimates.

Staff likewise located no data indicating that infrastructure and transport cost for biodiesel or hydrogen had changed significantly since 2009. Staff's estimate of the storage, transport, and distribution costs of hydrogen consisted of the EER-adjusted value from the Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies:[106] $0.57 per GGE.

g. Fuel Dispensing Costs

<u>E85:</u>

The E85 dispensing cost information presented in the 2009 analysis was not updated for this chapter. Staff identified no data on which to base such an update.

Dispensing E85 at an existing gasoline dispensing facility requires a 10,000 gallon tank, one dispenser with two nozzles, and lines to move the fuel from the storage tank to fuel pumps. The estimated costs of this infrastructure are shown in Table VII-5

Table VII-5
Cost of Installing E85 Dispensing Infrastructure
at an Existing Service Station (2010 dollars)[a]

Equipment & Parts	Installation	Permits	Soil Disposal & Testing	Total
$72,000	$87,000	$5,000	$8,000	$172,000

[a] Personal Communication, Mike Lewis, Pearson Fuels, 2008. The costs presented are based on an actual E85 installation at an existing service station.

<u>Hydrogen:</u>

The capital cost of constructing a hydrogen dispensing station ranges from $250,000 for a station capable of dispensing ten kilograms per day, to $5 million for a

[105] Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. February 2010. Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis. EPA-420-R-10-006.
[106] Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies, National Research Council, 2008. "Transitions to Alternative Transportation Technologies: A Focus on Hydrogen." The National Academies Press. Retrieved, from http://www.nap.edu/catalog.php?record_id=12222

1,000 kilogram-per-day station.[107] These are costs for stations that produce hydrogen on site using the steam methane reformation process. For this analysis, staff obtained costs for a 1,000 kilogram per day liquid delivery system for public fleets. The estimated capital cost for such a station is $2.7 million. Assuming annual sales of 173,000 kilograms of hydrogen (47 percent of the station's capacity), staff estimated that the EER-adjusted cost of a hydrogen station adds $3.60/per kg sold, or $1.57/GGE.

<u>CNG:</u>

Staff assumed that the increased use of CNG as a diesel substitute transportation fuel would require both increasing the capacity of existing CNG fueling infrastructure and building additional stations. Staff assumed that new CNG stations would be added to existing truck refueling stations along major freeways. Staff further assumed that one new station would be built for every five existing retrofitted stations, resulting in a 20 percent increase in the number of CNG fueling stations in the State. The new infrastructure required at existing CNG stations consists of a dispenser, a compressor, and a dryer. Staff assumed that one additional dispenser and compressor would be installed at existing stations so that two vehicles could be serviced simultaneously. A new station requires storage tanks, two dispensers, two compressors, and a dryer. The costs developed based on these assumptions are shown in Table VII-6.

Table VII-6
Estimated Cost of Upgrading Existing or Creating New CNG Fueling Station (2010 dollars)[a]

Facility Type	Dispenser with two hoses	400 CFM Compressor with Installation	New Dryer	(Storage, dispensing, compressing)	Total
Existing CNG Station	$57,500	$239,000	$76,500		$373,000
New CNG Dispenser at Existing Truck Stop	$57,500	$239,500		$717,500	$1,014,500

[a] Personal communication, Sempra Energy, December 2008.

<u>Electricity:</u>

In the 2009 analysis, staff estimated the costs of electricity based on tariffs from Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and the Los Angeles Department of Water and Power (LADWP). Table VII-7 identifies the tariff schedules used in the 2009 analysis.

[107] Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies, National Research Council, 2008. "Transitions to Alternative Transportation Technologies: A Focus on Hydrogen." The National Academies Press. Retrieved, from http://www.nap.edu/catalog.php?record_id=12222

Table VII-7
Electricity Tariffs Used in LCFS Economic Analysis

Load-Serving Entity	Tariff Schedule	Description
PG&E	R: E-9[a] (PGE9)	Experimental Residential Time-of-Use Service for Low Emission Vehicle Customers
	C: E-19[a] (PGE19)	Medium General Demand-Metered TOU Service
SCE	R: TOU-EV-1[b] (SCEEV1)	Domestic Time-of-Use Electric Vehicle Charging
	C: TOU-EV-4[b] (SCEEV4)	General Service Time-Of-Use Electric Vehicle Charging - Demand Metered
LADWP	R: R-1 Rate B[c] (LADWPR1)	Residential TOU with Electric Vehicle Credit
	C: A-2 Rate B[c] (LADWPA2)	General Service TOU with Electric Vehicle Credit

R = Residential, C = Commercial

[a] PG&E Electricity Tariffs: http://www.pge.com/tariffs/ERS.SHTML#ERS
[b] SCE Tariff Rates: http://www.sce.com/AboutSCE/Regulatory/tariffbooks/ratespricing/default.htm
[c] LADWP Electric Rates Schedules: http://www.ladwp.com/ladwp/cms/ladwp008881.jsp

Although there have been some modifications to some of these electricity tariffs since 2009, staff determined that the slight modifications would have no impact on the overall economic analysis for 2011, so we used the same estimated cost of electricity in the current analysis. 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. For residential customers charging light-duty vehicles, therefore, staff assumed that electricity would cost $0.09 per kilowatt-hour (kW-hr). For commercial customers charging medium- and heavy-duty vehicles, staff assumed $0.12/kW-hr. These costs translate to $2.89 and $3.85 per GGE, respectively. Adjusting each cost for the EER of electric-powered vehicles yields $0.96 and $1.28 per GGE respectively. To account for charger installation, staff rounded these EER-adjusted costs up to $1.00/GGE, for the gasoline scenarios and $1.33/GGE, for the diesel scenarios.

h. Summary of Lower-CI Fuel Costs

The costs for the lower-CI fuels considered in this analysis are summarized in Table VII-8.

Table VII-8
Lower-CI Fuel Costs ($/GGE, except for biodiesel [$/gal])[a]

Fuel	Feedstock	Capital Plant Costs	Production Costs	Co-product Cost Credit	Feed-stock	Storage, Transport, Dispensing	Grand Total
Ethanol	Corn (dry mill)	$0.30	$0.79	($.82)	$2.72	$0.33	$3.32[b]
Ethanol	Corn (wet mill)	$0.63	$0.83	($1.50)	$2.83	$0.33	$3.12[c]
Ethanol	Wood chips	$1.32	$0.63	($0.09)	$1.19	$0.33	$3.38[d]
Ethanol	Sugarcane (Brazil)[1]	$0.86	$0.73	$0.00	$0.43	$0.64	$2.73[e]
Ethanol	Corn stover	$1.19	$1.12	($0.14)	$1.60	$0.33	$4.08[f]
Ethanol	MSW	$1.30	$0.60	($0.09)	$0.72	$0.33	$2.86[g]
FAME Biodiesel	Soybean Oil	$0.12	$0.36	($0.32)	$3.88	$0.22	$4.27[h]
FAME Biodiesel	Yellow Grease (UCO)	$0.09	$0.67	($0.32)	$2.85	$0.22	$3.52[i]
FAME Biodiesel	Canola	$0.12	$0.36	($0.32)	$4.21	$0.22	$4.59[j]
FAME Biodiesel	Corn Oil	$0.12	$0.36	($0.32)	$4.15	$0.22	$4.53[k]
FAHC Diesel	Tallow	$0.30	$0.27	($0.32)	$3.60	$0.22	$4.07[l]
CNG[o]							$2.19[m]
Electricity[o]	California Marginal Generation	na	na	na	na	na	$3.00[n]
Hydrogen[o]	Coal Gasification	na	$0.00	$0.00	$0.00	$0.70	$2.60[o]
Hydrogen	Central Natural Gas	na	$0.00	$0.00	$0.00	$1.30	$3.00[p]

[a] Feedstock costs and co-product cost credits have been updated and are in 2010 dollars. The remaining costs are as reported in the 2009 Initial Statement of Reasons.
[b] Hosein Shapouri and Paul Gallagher (2002). USDA· 2002 Ethanol Cost of-Production Survey. US Department of Agriculture. 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. Imported ethanol assumed to be transported by rail and intrastate ethanol by truck
[c] Sparks Companies, 2002. Corn Based Ethanol Costs and Margins. Kansas State University. Imported ethanol assumed to be transported by rail and intrastate ethanol by truck
[d] 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.
[e] USDA (2006). The Economic Feasibility of Ethanol Production from Sugar in the United States. US Department of Agriculture. The cost benefit of using bagasse as process fuel is included in the production cost. Assumed transportation cost from plant to port $0.21/gal, port cost $0.10/gal and transportation from Brazil to U.S. $0.14/gal. Added 2.5% ad valorem tax.
[f] Andrew McAloon and et al., 2000. Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks. National Renewable Energy Laboratory

[g] Fulcrum Bioenergy, 2008. Plant to Provide an Attractive Domestic Alternative to High Priced Gasoline. Tomkinson, Jeremy. N.d. Feasibility of a Lignocellulosic Ethanol Facility in the UK. National Non-Food Crops Centre UK.
[h] Haas, Michael J. et al., 2006. "A process model to estimate biodiesel production costs." Bioresource Technology 97: 671-678
[i] Zhang, Y. et al., 2003. "Biodiesel production from waste cooking oil: 2. Economic assessment and sensitivity analysis." Bioresource Technology 90: 229-240.
[j] Antares Group, July 15, 2008. Strategic Assessment of Bioenergy Development in the West. Task 2: Bioenergy Conversion Technology Characteristics FINAL REPORT. Prepared for the Western Governors' Association. Canola biodiesel costs based on soy biodiesel costs.
[k] Antares Group, July 15, 2008 (see note i). Corn oil biodiesel costs based on soy biodiesel costs
[l] Antares Group, July 15, 2008 (see note i). Fatty Acids to HydroCarbon-Hydrotreatment (FAHC) analysis.
[m] CEC, Transportation Energy Forecasts and Analyses For The 2011 Integrated Energy Report: Draft Staff Report, 2011. Sacramento, CA.: CEC-600-2011-007-SD. The CNG retail prices used are from Table B-6, (Appendix B, page B-10), The tax amounts that were subtracted off are from Table B-5, page B-9 of the same document
[n] Rate Schedules for Pacific Gas and Electric Company, Southern California Edison, and Los Angeles Department of Water and Power. See Table VII-7, above.
[o] Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies, National Research Council, 2008. "Transitions to Alternative Transportation Technologies: A Focus on Hydrogen." The National Academies Press. Retrieved, from http://www.nap.edu/catalog.php?record_id=12222
[p] Local dispensing costs not included for hydrogen, CNG, and electricity. 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).

For the gasoline scenarios, staff did not differentiate among sources of corn ethanol, but used an average corn ethanol CI of 87.8 g CO_2/MJ, which represents the average corn ethanol CI from the LCFS biofuel producers' registration program and staff-approved Method 2A and 2B fuel pathway applications.

As discussed above, staff adjusted the liquid biofuel production and feedstock costs to reflect changes in the price of crude. Table VII-9 below shows the cost impacts of those adjustments.

Table VII-9
Estimated Impact of Changes in Crude Prices on Lower-CI Fuel Costs ($/GGE, except for biodiesel [$/gal])[a]

		Ethanol							Biodiesel				
Year	Projected Crude Price ($/bbl)[b]	Midwest Corn (dry mill)	Midwest Corn (wet mill)	Lignocell. (wood chips)	Sugarcane (Brazil)	Lignocell. (corn stover)	Green Wastes	FAME (Soybean Oil)	FAME, Yellow Grease (UCO)	FAME (Canola)	FAME (Corn Oil)	FAHC (Tallow)	CNG [c]
2011	97.3	$3.32	$3.12	$3.38	$2.73	$4.08	$2.86	$4.27	$3.52	$4.59	$4.53	$4.07	2.19
2012	103.1	$3.39	$3.18	$3.41	$2.74	$4.13	$2.88	$4.35	$3.58	$4.66	$4.60	$4.15	2.19
2013	106.5	$3.42	$3.22	$3.43	$2.75	$4.16	$2.89	$4.40	$3.62	$4.70	$4.64	$4.20	2.21
2014	110.1	$3.46	$3.26	$3.45	$2.76	$4.18	$2.91	$4.45	$3.66	$4.74	$4.67	$4.24	2.22
2015	112.8	$3.49	$3.29	$3.46	$2.77	$4.20	$2.92	$4.48	$3.69	$4.76	$4.70	$4.27	2.22
2016	113.2	$3.49	$3.29	$3.46	$2.77	$4.21	$2.92	$4.49	$3.69	$4.77	$4.71	$4.28	2.22
2017	113.4	$3.49	$3.30	$3.46	$2.77	$4.21	$2.92	$4.49	$3.69	$4.77	$4.71	$4.28	2.22
2018	113.5	$3.50	$3.30	$3.46	$2.77	$4.21	$2.92	$4.49	$3.69	$4.77	$4.71	$4.28	2.23
2019	113.3	$3.49	$3.30	$3.46	$2.77	$4.21	$2.92	$4.49	$3.69	$4.77	$4.71	$4.28	2.24
2020	113.1	$3.49	$3.29	$3.46	$2.77	$4.21	$2.92	$4.49	$3.69	$4.77	$4.70	$4.28	2.24

[a] All lower-CI fuel costs increase annually; however, slight annual differences may not be apparent due to rounding. Feedstock and co-product credit costs portion of production costs have been updated and are in 2010 dollars. All other costs are as reported in the 2009 Initial Statement of Reasons.

[b] The crude oil prices in this table are derived from wholesale prices developed by the California Energy Commission. Please see footnote a to Table VII-1

[c] Based on CEC, Transportation Energy Forecasts and Analyses For The 2011 Integrated Energy Report: Draft Staff Report, 2011. Sacramento, CA.: CEC-600-2011-007-SD. Amounts are in units of EER adjusted dollars per GGE. CNG cost increases were based on CEC's retail price estimates are not directly related to crude prices.

i. Alternative-Fuel Tax Incentives

<u>Ethanol Tariff:</u>

Staff assumed the ethanol tax credits and the Brazilian sugarcane tariff and tax will sunset and, therefore, excluded them from the 2011 analysis. Both were accounted for in the 2009 analysis.

<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. Staff accounted for this tax incentive for the 2009 analysis.

3. Comparison of Fuel Production and Distribution Costs for Gasoline Illustrative Scenarios

In order to estimate the cost-of-production-based economic impacts of the LCFS, staff applied the fuel cost information developed above to the illustrative scenarios presented in Chapter VI. This yielded a series of volume-weighted aggregate fuel production costs for each year between 2011 and 2020. All fuels included in the scenarios are included in the averages reported below. The weighting is by the total volume of each fuel used in the scenario. The scenarios are structured so as to capture all reasonably foreseeable variation in the California fuel mix through 2020. By applying the cost estimates to those scenarios, therefore, all reasonably foreseeable variation in costs can be captured. In this way, potential future LCFS-driven fuel cost changes can be bracketed between minimum and maximum amounts. The actual cost change would most likely fall somewhere between these endpoints.

Scenario-specific per-gallon production cost estimates for gasoline and gasoline substitute fuels are shown in Table VII-10. The baseline case is the without-LCFS case. It is a business-as-usual case which includes the fuels brought into the state by the federal Renewable Fuels Standard. Please see Chapter VI for details.

Table VII-10:
Gasoline and Gasoline Substitute Fuel Costs (2010 dollars per gallon)

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Baseline	2.562	2.592	2.667	2.746	2.805	2.806	2.810	2.811	2.806	2.800
Scenario 1	2.562	2.589	2.661	2.732	2.776	2.743	2.743	2.742	2.734	2.737
Scenario 2	2.562	2.591	2.666	2.743	2.796	2.783	2.780	2.770	2.768	2.772
Scenario 3	2.562	2.592	2.667	2.742	2.779	2.760	2.731	2.711	2.685	2.665
Scenario 4	2.562	2.589	2.662	2.737	2.783	2.765	2.748	2.728	2.706	2.681
Scenario 5	2.562	2.592	2.667	2.744	2.821	2.817	2.845	2.863	2.873	2.887
Scenario 6	2.562	2.592	2.667	2.743	2.812	2.808	2.830	2.850	2.860	2.871
Scenario 7	2.562	2.592	2.667	2.743	2.811	2.808	2.830	2.852	2.856	2.868
Scenario 8	2.562	2.592	2.667	2.743	2.801	2.792	2.797	2.805	2.799	2.809
Scenario 9	2.562	2.592	2.667	2.743	2.814	2.821	2.846	2.867	2.873	2.887
Scenario 10	2.562	2.592	2.667	2.743	2.812	2.815	2.840	2.858	2.864	2.873
Scenario 11	2.562	2.592	2.667	2.743	2.803	2.805	2.815	2.825	2.828	2.838

In order to assess the fuel cost impacts of the LCFS, baseline per-gallon cost estimates were subtracted from the corresponding annual estimate for each scenario. The results for the gasoline and gasoline-substitute scenarios are shown in Table VII-11.

Table VII-11:
Gasoline and Gasoline Substitute Cost per Gallon Differentials: Scenario minus Baseline (Negative Values in Parentheses) (2010 dollars per gallon)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Scenario 1	0.00	(0.00)	(0.01)	(0.01)	(0.03)	(0.06)	(0.07)	(0.07)	(0.07)	(0.06)
Scenario 2	0.00	(0.00)	(0.00)	(0.00)	(0.01)	(0.02)	(0.03)	(0.04)	(0.04)	(0.03)
Scenario 3	0.00	0.00	0.00	(0.00)	(0.03)	(0.05)	(0.08)	(0.10)	(0.12)	(0.13)
Scenario 4	0.00	(0.00)	(0.01)	(0.01)	(0.02)	(0.04)	(0.06)	(0.08)	(0.10)	(0.12)
Scenario 5	0.00	0.00	0.00	(0.00)	0.02	0.01	0.03	0.05	0.07	0.09
Scenario 6	0.00	0.00	0.00	(0.00)	0.01	0.00	0.02	0.04	0.05	0.07
Scenario 7	0.00	0.00	0.00	(0.00)	0.01	0.00	0.02	0.04	0.05	0.07
Scenario 8	0.00	0.00	0.00	(0.00)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	0.01
Scenario 9	0.00	0.00	0.00	(0.00)	0.01	0.02	0.04	0.06	0.07	0.09
Scenario 10	0.00	0.00	0.00	(0.00)	0.01	0.01	0.03	0.05	0.06	0.07
Scenario 11	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	0.01	0.01	0.02	0.04

As Table VII-11 shows, the estimated cost-of-production impacts of the LCFS on gasoline and gasoline-substitute fuels are likely to range between a cost increase of \$0.09 per gallon, and a cost decrease of \$0.13 per gallon. Both of these extreme values occur in 2020: Scenario 3 yields the lowest price increase (a \$0.13 savings), and scenarios 5 and 9 yield the highest increase (\$0.09). The median cost change value for this range is -\$0.02 per gallon. Overall, however, these results hover around zero, indicating that the cost of producing lower-CI alternative fuels to comply with the LCFS is unlikely to drive a significant cost change in the gasoline fuel mix over the 2011-2020 time horizon. However, as was mentioned in the preface to this chapter, this cost-of-production analysis does not take into account any carbon-intensity-based price effects, which will be the subject of continuing economic analyses with CEC staff and other interested stakeholders.

4. Comparison of Fuel Production and Distribution Costs for Diesel Fuel Illustrative Scenarios

Scenario-specific per-gallon production cost estimates for diesel and diesel substitute fuels are shown in Table VII-12. These correspond to the gasoline fuel costs appearing Table VI-10.

Table VII-12:
Diesel and Diesel Substitute Fuel Production Costs (2010dollars per gallon)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Baseline	2.884	2.862	2.945	3.031	3.095	3.104	3.112	3.117	3.115	3.110
Scenario 1	2.854	2.818	2.973	3.112	3.196	3.275	3.346	3.333	3.313	3.284
Scenario 2	2.854	2.818	2.968	3.112	3.196	3.277	3.351	3.340	3.324	3.301
Scenario 3	2.854	2.818	2.968	3.112	3.198	3.279	3.356	3.347	3.330	3.309
Scenario 4	2.854	2.818	2.965	3.112	3.200	3.283	3.361	3.351	3.335	3.314
Scenario 5	2.854	2.818	2.962	3.104	3.203	3.288	3.375	3.367	3.354	3.338

The diesel and diesel fuel cost assessment parallels the gasoline fuel cost assessment presented above (Table VII-11 and related discussion): baseline per-gallon cost estimates were subtracted from the corresponding annual estimate for each scenario. The results for the diesel and diesel-substitute scenarios are shown in Table VII-13.

Table VII-13:
Diesel and Diesel Substitute Fuel Cost per Gallon Differentials: Scenario minus Baseline (Negative Values in Parentheses)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Scenario 1	(0.03)	(0.04)	0.03	0.08	0.10	0.17	0.23	0.22	0.20	0.17
Scenario 2	(0.03)	(0.04)	0.02	0.08	0.10	0.17	0.24	0.22	0.21	0.19
Scenario 3	(0.03)	(0.04)	0.02	0.08	0.10	0.17	0.24	0.23	0.22	0.20
Scenario 4	(0.03)	(0.04)	0.02	0.08	0.10	0.18	0.25	0.23	0.22	0.20
Scenario 5	(0.03)	(0.04)	0.02	0.07	0.11	0.18	0.26	0.25	0.24	0.23

The diesel fuel cost impacts appearing in Table VI-13 range from a cost decrease of \$0.04 (all scenarios in 2012) to a cost increase of \$0.26 (scenario 5 in 2017). This result indicates that the cost of producing renewable diesel and biodiesel to comply with the LCFS may increase diesel costs somewhat over the term of the regulation. The general cost trend apparent in Table VI-13 is a transition from slight cost declines in 2011 and 2012 to cost increases through 2017. All increases shown exceed \$0.20 per gallon. In the 2017-2020 period, costs remain relatively level.

VIII. Environmental Impacts

A. Introduction

This chapter's focus is on health impacts, air quality, sustainability, and other environmental effects of the LCFS. The chapter begins with a summary of the analysis that staff performed in 2009, which included an evaluation of the potential environmental impacts of the LCFS. We also discuss whether there is significant change from the data used in the original analysis; if the fuel pool in California has fundamentally changed; and if the existing permitting process is sufficient to prevent any adverse impacts on local, state, and federal levels. Additionally, we cover potential mitigation measures that can be used to minimize local impacts. We discuss the protocol that staff has developed for identifying proposed projects potentially related to the LCFS and the biorefinery siting guidance document, which was developed as a guide for local air districts. Lastly, we discuss how sustainability will be addressed along the full supply chain (i.e., from the field to the biorefinery), how its criteria can inform and support future environmental impact assessments, and whether we are collecting the necessary data to continue to monitor potential environmental impacts of the LCFS as the program moves forward.

This chapter addresses topics 9, 10 and 12 from the regulation that require consideration of the following areas:

(9) An analysis of the public health impacts of the LCFS at the State and local level, including the impacts of local infrastructure or fuel production facilities in place or under development to deliver low carbon fuels, using an ARB-approved method of analysis developed in consultation with public health experts from academia and other government agencies;

(10) An assessment of the air quality impacts on California associated with the implementation of the LCFS; whether the use of the fuel in the state will affect progress towards achieving state or federal air quality standards, or results in any significant changes in toxic air contaminant emissions; and recommendations for mitigation to address adverse air quality impacts identified; and

(12) Significant economic issues; fuel adequacy, reliability, and supply issues; and environmental issues that have arisen.

Through this review process, staff has determined that the public health and air quality impacts estimated in 2009 have not changed significantly throughout the first implementation year of the LCFS. The minimum impacts are due to many factors, including only slight changes in California's transportation fuel consumption, which cannot be solely attributed to the LCFS; no new fuel facilities being built in the state since the 2009 environmental impacts analysis; and no new fuels that could potentially be used in the State completing the multimedia process. As suggested, because 2011 is the first implementation year, the program is still in its infancy. The changes expected in the early years will be relatively minor. It should be noted that some panelists felt that ARB staff's scope of environmental impacts is too restricted and should take into account the effects of all fuels, rather than focusing on biofuels.

That being said, as the LCFS annual carbon-intensity (CI) standards get more stringent, additional fuels will undergo the multimedia process, and investment will begin to flow more freely to ultra-low carbon fuel producers, so there will be impacts associated with the LCFS program—potentially positive or negative. Ongoing monitoring and assessment of emission impacts, as well as promotion of sustainability principles for air quality and other environmental concerns is necessary to protect against unintended negative outcomes. Staff has developed two methods to help ensure the preservation of air quality due to changes in the transportation fuel sector. The first method includes drafting the biorefinery siting guidance document for local air districts, other agencies, and community members to use to minimize air pollution from biorefineries, and fulfilling the directive from the Board to participate in the environmental review of proposed projects, working with local air districts and others. For the second method, ARB will continue monitoring the state of transportation fuels within California as well as the accompanying infrastructure and vehicles associated with these transportation fuels.

B. Summary of the 2009 Environmental Analysis

The original environmental analysis focused on the significant GHG reductions that the regulation would provide due to the production and use of lower-CI transportation fuels. It also included the potential reductions due to changes in the vehicle fleet composition that would available to use these lower-CI transportation fuels. Staff estimated that a reduction of about 16 million metric tons of CO2-equivalent (MMTCO2e) would come solely from the combustion of transportation fuels in California in 2020. If the full-fuel-lifecycle is included in the GHG benefits of the LCFS—taking into account GHG reductions outside of California—there would be an estimated reduction of about 23 MMTCO2e.

As part of the analysis, staff estimated the number of potential new transportation fuel facilities that could be built in California. This estimate relied on the volume of biomass available in the State, projects that were undergoing the permitting process at the time of the analysis, and the projected demands of both the LCFS and RFS2 in 2009. It was estimated that a potential six ethanol facilities, 18 cellulosic ethanol facilities, and six biodiesel facilities could be operational in the State by 2020. In the 2009 analysis, staff did not anticipate any changes in the emissions from petroleum refineries, power plants, or existing corn facilities over the baseline projections. We assumed that refining would not ramp up or slow down based solely on California consumption. We also assumed that any additional electricity use would be offset by the switch to a 33 percent renewable portfolio standard and off-peak charging. Lastly, at the time of writing the staff report, the California corn ethanol facilities were among the cleanest in the nation and we did not anticipate them needing to upgrade their facilities within the 2020 time frame. Therefore, any impacts above the baseline were attributed solely to potential new biorefinery facilities operating in the State.

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

Staff performed a health risk assessment to estimate the potential cancer risk from a biorefinery. To establish a plausible upper-bound, staff evaluated a scenario consisting of three co-located facilities. Details of this analysis can be found in Chapter VII of the 2009 ISOR. The highest potential cancer risk associated with on-site emission risk was estimated to be 0.4 chances per million at the fence line of the facility. When including both on-site and off-site emissions in the risk analysis, it was estimated to be 5 chances per million. In addition to the potential cancer risk, staff also analyzed the impacts related to PM2.5. This analysis estimated an additional 20 premature deaths, seven hospital admissions, and 314 cases of asthma, acute bronchitis, or lower respiratory symptoms.

When staff analyzed the ambient ozone impacts, it was determined that the air quality model could not reliably predict the impact because the concentrations of smog-forming pollutants associated with the LCFS were not statistically significant above the baseline.

Lastly, staff provided qualitative, and in a few cases quantitative, evaluations of impacts on other types of media. The evaluations included water use and water quality, agricultural resources, biological resources, geography and soils, hazardous materials, mineral resources, solid waste, and others. There was also a brief discussion on the commitment to develop a plan to address sustainability components related to the production of feedstock and transportation fuels.

C. Tools and Methods for Assessing the Environmental Impacts in the 2009 Staff Report

1. Greenhouse Gas Emission Benefits

In the GHG analysis, staff 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. In a "tank-to-wheel" analysis, 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 the second analysis, staff used the full lifecycle carbon intensity to estimate the overall CO2 emission reductions associated with the LCFS.

One of the key parameters underlying the LCFS is estimating the volumes of fuels needed to propel California's vehicle fleet each year. Staff estimated projections 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. By estimating the emissions associated with these petroleum-based fuels, and the alternative fuels used to displace a portion of them, staff can calculate the GHG emission reduction benefits of the LCFS.

2. Health Risk Assessment

Staff conducted a health risk assessment (HRA) study to evaluate the potential 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 PM emissions associated with biofuel facilities. Specifically, the analysis focused on the diesel PM emissions from vehicles expected to deliver feedstocks to biofuel facilities.

The 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.

3. 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.

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 the same locations to achieve attainment.

4. 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. For the 2009 staff report, ARB staff quantified seven non-cancer health impacts associated with the change in exposure to NOx and PM2.5 emissions from increased transportation associated with new biorefineries and transporting imported ethanol within California. This analysis has been updated since the March 2009 ISOR was published to include: 1) updated emissions factors, 2) potential emissions benefits of advanced vehicles and 3) recognition of the potential programmatic overlap with the federal RFS2 program.

5. Multimedia Evaluation

Senate Bill 529, enacted in 1999 and set forth in Health and Safety Code (H&S) section 43830.8, generally prohibits ARB from adopting a regulation establishing a specification for motor vehicle fuel unless the fuel undergoes a multimedia evaluation. Since the LCFS is not a fuel specification, it does not trigger additional multimedia evaluations, although any new fuel introduced into California would be subjected to this analysis.

“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.”

To oversee the multimedia evaluation process, the California Environmental Protection Agency formed the multimedia working group (MMWG), which makes recommendations to the California Environmental Policy Council (EPC) regarding the acceptability of the fuel and any significant adverse impacts on public health or the environment.

Proposed future rulemakings that may establish motor vehicle fuel specifications may be subject to H&S §43830.8 and include biodiesel, compressed natural gas, E85, and biobutanol, although some fuels may be well characterized and may undergo and expedited review.

D. New Tool and Methods Developed to Aid in the LCFS Reviews Moving Forward

1. Proposed Review Protocol for CEQA Documents

a. Introduction

Resolution 09-31 for the Low Carbon Fuel Standard (LCFS) ARB staff to participate in the environmental review of projects in California directly related to the production, storage, and distribution of transportation fuel subject to the LCFS program. ARB staff has two primary opportunities to participate in the review of the air quality impacts of proposed new and expanding biorefinery projects through our role in (1) the California Environmental Quality Act (CEQA) process, and (2) the local air district permitting process. Flow charts illustrating the CEQA process and general district permitting process are attached, as Figures 1 and 2.

b. CEQA Process

A CEQA review usually requires the participation of local planning agencies, local air districts, and state agencies. Under CEQA, these agencies serve as lead agencies[108], responsible agencies[109], or interested agencies.[110] For biorefinery projects in California, it is expected that the city or county planning department will serve as the lead agency, the district will serve as a responsible agency, and the ARB will participate as an interested agency.

ARB staff does not expect biorefinery projects to be exempt from CEQA review nor to qualify for a negative declaration under CEQA, and therefore expects that the CEQA lead agency will be required to prepare a detailed environmental impact report (EIR).[111] The CEQA review is separate from the local air district's normal New Source Review permit process, although the two reviews may have some common considerations and requirements. The local air district (district) would assist the lead agency in specifying and reviewing information needed for evaluation of the project pertaining to air quality. When participating as a responsible agency, the district's decision-making must consider the lead agency's findings regarding air quality impacts.

The scope of the CEQA review for air quality could be substantially greater than that for district permit issuances. A CEQA review must include the effect of suspected toxic emissions and non-criteria emissions for which there are limited or no regulatory requirements yet developed, an analysis of cumulative air quality impacts, an analysis of project alternatives, and the analysis of source-related emissions (such as from motor vehicles associated with the project).

An EIR is usually produced in draft or initial versions that are followed by a final product. In accordance with the CEQA process, the draft EIR will be available for review by responsible agencies, interested agencies, and the public during the public review period, which is generally 30 days. The State Clearinghouse of the Governor's Office of

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[108] The CEQA lead agency is the public agency that has the principal responsibility for carrying out or approving a project and is responsible for determining whether the project will have a significant effect on the environment. The lead agency is normally the agency with general governmental powers, such as a city or county, rather than an agency with a single or limited purpose such as an air district.
[109] An agency with discretionary permitting authority, besides the lead agency, is the responsible agency.
[110] Regulatory agencies with no permitting authority for a biorefinery project may still act as interested agencies and may participate in the evaluation of the environmental impacts of a project through the normal public review period built into the CEQA process.
[111] The purpose of the EIR is to assess any significant effect on the environmental by the project and to evaluate potential mitigation measures.

Planning and Research coordinates the distribution of environmental documents prepared under CEQA to state agencies for their review and comment.

c. Local Air District Permitting Process

In addition to the environmental review process that takes place under CEQA, a project that is a direct source of emissions will also need a permit from the local air district. The permitting process starts with the submission of an application. The application will contain pertinent information such as equipment to be installed and processes that may emit air pollutants. After the district deems an application complete, the district normally has up to six months to process the application. During the application review period, most districts will prepare an engineering analysis that documents emission calculations, satisfaction of applicable district and state air quality regulations, assumptions used to evaluate the acceptability of the project, and required conditions of design and operation to achieve and maintain compliance. Many districts will also generate proposed permits (authorities to construct) that detail the specific air quality related operational and administrative requirements with which the facility must comply. If the project is large enough, a 30-day public review and comment period is required before a final district decision on the project. If public review and comment is required, the engineering analysis and proposed permits are made available to Region 9 of the United States Environmental Protection Agency, ARB, and the public.

d. ARB Participation in CEQA and District Permitting

The Project Assessment Branch within the ARB's Stationary Source Division receives CEQA documents that are filed with the State Clearinghouse, as well as district proposed authority-to-construct permits that trigger a public notice.

ARB staff will review all CEQA documents received for biorefinery projects submitted via the State Clearinghouse and all authority-to-construct permits submitted by the districts. ARB staff's role will be to provide comments to ensure that the proposed CEQA conditions of certification and district permit conditions will comply with all applicable orders, rules, and regulations of the district and the ARB, and are consistent with the recommendations outlined in ARB's Air Quality Guidance for Siting Biorefineries in California (November 2011)[112]. If deficiencies are noted, ARB staff will submit comments on the environmental documents prior to the end of the public review period.

ARB staff is confident that it will receive adequate notice of new and expanding biorefinery projects via the established CEQA review and district permit review mechanisms described above, as well as through staff's regular interaction with the California Air Pollution Control Officers Association on district permitting issues.

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[112] Available at: http://www.arb.ca.gov/fuels/lcfs/bioguidance/bioguidance.htm

2. Air Quality Guidance for Siting Biorefineries in California

a. Introduction

Implementation of the LCFS may result in the installation of new biofuel production facilities (herein referred to as biorefineries) and expansion of existing facilities in California. In the LCFS rulemaking documents, ARB staff recommended that the emissions associated with biorefineries be fully mitigated consistent with local air pollution control and air quality management district (district) and California Environmental Quality Act (CEQA) requirements. To assist with this process, ARB staff has developed the Air Quality Guidance for Siting Biorefineries in California (guidance or report)[113] to help stakeholders in assessing and mitigating air emissions associated with biorefinery activities in California.

The guidance addresses both stationary-source and mobile-source emissions associated with biorefinery operation. The primary purpose of this guidance is to: (1) identify the most stringent permitted emission limits from individual pieces of process equipment currently used or expected to be used at biorefineries, and (2) identify available options for mitigating air emissions from mobile sources at biorefineries.

This guidance is intended to provide districts, regulated parties, and other stakeholders with information that can be used to ensure that new or expanding biorefineries are constructed and operated in a way that eliminates or minimizes adverse air quality impacts. While this guidance is intended to promote general consistency in local permitting decisions, ARB recommends interested parties consult their local air district for specific requirements.

b. Background

This section briefly discusses the content of the guidance. Stakeholders should consult the actual guidance report for additional details and complete information regarding the recommendations made in this report.

i. Purpose of Guidance

The purpose of this report is to provide guidance to assist districts, local land use planners, environmental and public health groups, project proponents, and other stakeholders in site selection, air quality permitting considerations, and identification of potential CEQA mitigation measures. The guidance can assist stakeholders in evaluating the relative air quality impacts of various conversion technology options that are available for biofuels. Proponents of biorefinery projects may use the guidance to inform environmental and public health groups and other interested stakeholders about the emissions levels of proposed stationary equipment at biorefineries and the range of options that could be used to mitigate mobile source emissions that are associated with the construction and operation of biorefineries. The guidance is not intended to

[113] http://www.arb.ca.gov/fuels/lcfs/bioguidance/bioguidance.htm

substitute case-by-case permitting decisions conducted by local air quality, environmental, or planning agencies. In addition, this report is not intended to preempt, replace, or devalue the decision-making processes that are associated with the outcomes of transportation planning analyses, site specific air quality modeling, risk assessments, SIP modeling, or future rules and regulations adopted for the purpose of controlling emissions of criteria pollutants, toxic air contaminants (TAC), or greenhouse gases (GHG).

ii. Biofuel Processes Evaluated

The information in the guidance was compiled from ARB staff's evaluation of the types of biofuels that could potentially be produced at a California biorefinery, the commercially available conversion technologies used to produce these fuels, the process equipment and air pollutants associated with these technologies that would be subject to district permit requirements, and the most current stringent permitted emission levels for these processes. The biofuels evaluated include: ethanol from grains, sugarcane, and cellulose; biodiesel; renewable diesel; biogas; hydrogen; and biogasoline. The conversion technologies evaluated include: fermentation, hydrolysis, gasification, transesterification, anaerobic digestion, reformation, and acid fermentation. Staff also evaluated motor vehicles and mobile equipment that would typically be associated with biorefineries. These could include trucks used to deliver raw material to a facility, excavators used to maintain the facility infrastructure, and chippers used to process raw material.

iii. Air Pollutants Addressed

The air pollutants evaluated include: oxides of nitrogen (NOx), particulate matter (PM), volatile organic compounds (VOC), oxides of sulfur (SOx), carbon monoxide (CO), and toxic air contaminants (TACs). Corresponding ammonia (NH3) slip emission limits for stationary sources equipped with control technologies that use ammonia for the reduction of NOx are identified in the report for informational purposes.

Strategies to specifically mitigate GHG emissions from biorefineries were not evaluated, and ARB staff has deferred to the work being undertaken to satisfy the requirements in the California Global Warming Solutions Act of 2006, Assembly Bill 32 or AB 32. However, many of the mitigation strategies identified in the guidance will provide GHG reductions by promoting overall efficiency in energy conversion technologies and encouraging the recovery of energy and other marketable products from biomass feedstocks.

iv. Topics Covered

The guidance addresses the following areas:

California’s air regulatory structure and regulation of stationary sources: Provides a broad overview of the air regulatory structure in California, major provisions for permitting stationary equipment at new or expanding biorefineries, and CEQA requirements that apply to proposed projects in the State;

Biofuel production conversion technologies and stationary source emissions: Describes commercially available biofuel pathways and conversion technologies, identifies stationary process equipment associated with each biofuel pathway, and identifies the air pollutants associated with each process;

Most stringent emission limits for stationary source equipment at biorefineries: Discusses the emissions data evaluated by ARB staff and staff's rationale in identifying the most stringent permitted emission limits for stationary equipment at biorefineries;

Mitigation of mobile source emissions associated with biorefineries: Identifies vehicle and mobile equipment associated with new or expanding biorefineries, ARB mobile source regulations, and options to mitigate emissions from mobile sources at biorefineries; and

Other considerations and future updates: Identifies other factors to consider when evaluating the impacts of a new or expanded biorefinery, such as proximity to low-income communities identified as highly impacted by air pollution and other socioeconomic factors, the need for possible additional mitigation measures, and outlines the update process for the guidance.

c. Recommendations

The basis for the recommendations in the guidance are the result of ARB staff's compilation of the most current stringent emission limits for process equipment used at biorefineries and options available to mitigate mobile source emissions associated with biorefineries, through review of:

- Adopted and proposed district rules;
- Control techniques required as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER);
- Emission levels achieved in practice, as verified by test results;
- More stringent control techniques which are technologically and economically feasible, but are not yet achieved in practice;
- Business, Transportation, and Housing and the California Environmental Protection Agency's Goods Movement Action Plan (2007);
- California Air Pollution Control Officers Association's Health Risk Assessment for Proposed Land Use Projects (2009);
- California Air Resources Board's Air Quality and Land Use Handbook: A Community Health Perspective (2005);
- State and local CEQA guidelines; and
- Draft and final Environmental Impact Reports (EIR) for various industrial facilities.

i. Stationary Source Emission Limits from Biorefineries

Tables 1, 2, and 3 in Appendix D summarize the most stringent emission limits for stationary process equipment that might be used at biorefineries. The tables are classified by equipment type—evaporative loss sources, combustion sources, and miscellaneous sources. ARB staff will continue to evaluate new emissions data and periodically provide updates using the process described later in this chapter.

ii. Mitigating Mobile Source Emissions from Biorefineries

On-road vehicles, off-road vehicles, and portable equipment used at biorefineries are a source of criteria pollutants, TACs, and GHGs. ARB staff recommends that on-road trucks serving biorefineries should have at a minimum 2007 model year or better engines, especially in areas where residents and sensitive receptors are present. To put this into context, an average on-road diesel truck equipped with a 2003 model year engine operating for an 8-hour day emits approximately 21 pounds per day NOx and 0.5 pounds per day PM. Whereas, that same truck equipped with a 2007 model year engine emits 6 pounds per day NOx (71 percent reduction) and 0.05 pounds per day PM (90 percent reduction). In addition, if that truck was equipped with a 2010 model year engine, the NOx emissions would be even less at about 1 pound per day (a 95 percent reduction compared to 2003 model year). Other options to mitigate mobile source emissions associated with biorefineries include repower, retrofit, new purchases, replacement, or use of alternative fuels to achieve earlier, more aggressive, or more comprehensive (e.g., including exempt equipment) emission reductions that go beyond regulatory requirements for in-use diesel-fueled mobile sources. Additional mitigation options are detailed in the full guidance report.

iii. Considerations for Highly Impacted Communities

Some communities in California are disproportionately impacted by air pollution from multiple sources. Any environmental analysis for a new or expanding biorefinery project should include consideration of these cumulative impacts, public vetting of those impacts, and recommendations for mitigation of any significant impacts. The guidance provides various tools for stakeholders to use during the project-specific analyses for new or expanding biorefinery projects that pertain to community impacts in areas that are already disproportionately affected by air pollution.

iv. Additional Strategies

In addition to the guidance provided for stationary-source process equipment and mitigation of mobile-source emissions, the report contains broader strategies that could be used to mitigate emissions from biorefineries.

Some of the mitigation strategies include:

- Use of onsite distributed generation (DG) and combined heat and power (CHP) systems in the form of fuel cells, microturbines, and other ultra-clean technologies; and

- The use of pipeline injection of biogas, rather than on-site combustion of biogas as a strategy to reduce emissions of NOx in areas that do not achieve the federal or State Ambient Air Quality Standards for ozone.

d. Updates to the Guidance

ARB staff's near-term update activities will focus on the distribution of new and updated BACT determinations, new source test results, new technologies, newly approved regulations (including test methods), and an updated list of existing biorefineries in California. This information will be posted to ARB's Biorefinery Guidance website[114]. ARB staff will send e-mail notifications to the LCFS listserve at ARB and the Bioenergy listserve at CEC when new information is posted to this website. ARB staff plans to provide these updates on a periodic basis or as biorefinery project activity dictates.

In addition, to ensure the information provided in this report stays current, ARB staff will perform periodic updates at intervals that correspond to the review periods set forth in the LCFS regulation. As part of these updates, staff will assess the geographic distribution of biorefineries in the state, and where appropriate, integrate additional mitigation measures for the purpose of protecting against disproportionate air quality impacts that arise from the concentration or co-location of multiple biorefineries.

E. Sustainability and the LCFS

1. Introduction

ARB staff is currently conducting a public process to evaluate sustainability standards that may be considered for the LCFS in the future. When the Board approved the LCFS on April 23, 2009, it directed staff in Resolution 09-31 to work with the Interagency Forest Work Group (IFWG), appropriate state agencies, environmental advocates, regulated parties, and other interested stakeholders to present a work plan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. Furthermore, the Board stated that the work plan should provide a framework for how sustainability provisions could be incorporated and enforced in the LCFS program, and it should include a schedule for finalizing feasible and appropriate sustainability provisions by no later than December 2011.

Sustainability is generally considered to be the ability to meet the needs of the present without compromising the ability of future generations to meet their own needs. A more scientific definition would be: the long term viability of natural resource consumption in balance with the supporting ecosystem. The three major components of sustainability are environmental, social, and economic sustainability.

[114] http://www.arb.ca.gov/fuels/LCFS/bioguidance/bioguidance.htm

2. Key Elements for Addressing Sustainability within the LCFS

This section briefly discusses some of the key elements of the proposed sustainability framework. A report[115] published by researchers at the University of California at Davis (UC Davis) examined a range of sustainability requirements for biofuels and considered a possible framework for LCFS sustainability provisions.

The study reviewed sustainability requirements and criteria being implemented or proposed by governments promoting biofuel programs—particularly the United Kingdom and the European Union. The study also reviewed the sustainability principles and criteria proposed by the Roundtable on Sustainable Biofuels (RSB). RSB is an international initiative involving stakeholders across the entire biofuel supply chain, nongovernmental organizations, experts, governments, and inter-governmental agencies.

Some of the key elements identified in the study for a sustainability provision include:

- Principles and criteria
- Benchmarking and/or third-party certification requirements
- Supply chain and reporting requirements
- Legality

ARB staff, through a public process and its sustainability workgroup, is evaluating how these provisions should be applied to the LCFS.

F. Changes in the California Transportation Fuel Pool

In Chapter VI of this review, staff presented the past consumption and future demand of transportation fuels. It was apparent from the data that in 2008 there was a decrease in the volume of major transportation fuels, with the exception of increased volumes of ethanol. The increase in ethanol consumption is due to the fact that California has moved from E6 to E10 in 2010. The increase was anticipated in the original analysis and therefore included in the 2009 baseline environmental impacts. Staff does not believe that these slight variations are caused by the LCFS and any small fluctuations can be attributed to factors outside of the LCFS, such as the economy. These small fluctuations did not lead to a significant change in the impacts from the 2009 impact assessment.

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[115] Yeh, S.; Summer, D.; Kaffka, S.; Ogden, J.; Jenkins, B. *Implementing Performance-Based Sustainability Requirements for the Low Carbon Fuel Standard – Key Design Elements and Policy Considerations*; Research Report UCD-ITS-RR-09-05; Institute of Transportation Studies, University of California, Davis: Davis, CA, 2009.

1. *Changes to the Data Used to do the 2009 Impact Analysis*

At this time, there have been no significant changes in the transportation fuel production capacity in California. No additional production facilities have been added since the baseline and impacts were calculated in 2009. Additionally, there have been no significant updates to the emission factors used in the 2009 analysis. In relation to additions in infrastructure, there has been an increase in E85 and biodiesel stations; however, past consumption data does not show an increase in consumption since the original environmental impacts analysis. Additionally, the increase in these stations cannot, with certainty, be associated with the LCFS. The increase can also be related to the federal RFS2, as it plays a role in the consumption of ethanol and biodiesel.

There are several multimedia evaluation updates that are being conducted that potentially impact the environmental analysis. These updates would most likely have a positive impact on the environment with relation to the LCFS. The updates include biodiesel, E85, CNG, and biobutanol. Once these evaluations are complete and updates are proposed to the fuel specifications, staff intends to update the impacts analysis. In addition to the multimedia process, staff intends to use data found in the LCFS reporting tool to estimate the GHG benefits.

2. *Anticipated Environmental Impacts for 2011*

Based on the current data available compared to the data of 2009, staff does not believe that there is a significant difference in the transportation fuels used in the State to warrant a new environmental impacts analysis. Staff will prepare another quantitative review of the impacts once more data is collected through the multimedia process.

There are several potential new aspects to the LCFS that may identify additional positive or negative environmental impacts of the LCFS, such as the sustainability provisions, adjusted land use values, and amendments to the HCICO provisions in the LCFS. Staff has proposed regulatory amendments including HCICO adjustments and other improvements to the LCFS regulation. When proposing amendments, staff is required to do an environmental and economic impact assessment of those proposed amendments. These analyses will be included in the staff report associated with the proposed regulatory amendments.

G. *Summary and Conclusions*

Since the initial staff report in 2009, staff has been continuing to monitor the potential environmental impacts of the LCFS. From monitoring the changes in the transportation fuel pool, the production facilities, and the permitting processes, there are no significant changes to the environmental impacts analysis originally conducted in 2009. In addition to this monitoring, we have been progressing on several key elements that will continue to support ARB's healthy air and environmental quality mission as well as successful implementation of the LCFS. These include: developing sustainability provisions; implementing a review process for CEQA documents related to transportation fuel projects; and developing a guidance document for the air quality districts related to siting practices. It should be noted that some panelists felt that ARB staff's scope of environmental impacts is too restricted and should take into account the effects of all fuels, rather than focusing on biofuels.

Although two years have passed since the adoption of the LCFS, 2010 was a reporting year and 2011 was the first implementation year for which a reduction in the carbon intensity of transportation fuels is required. Because this review is occurring early on in the program, there are not enough data to suggest that there are adverse environmental impacts associated with the LCFS. Staff will continue to monitor the progress of the program and will revisit the environmental impact analysis again for the 2015 review.

IX. High Carbon Intensity Crude Oil

A. Overview

The HCICO provision currently in the regulation was established to ensure that the ten percent reduction goal of the LCFS program would not be diminished if there is an increase in the high carbon-intensity of crude oils used by California refineries (and the resulting gasoline and diesel carbon intensity). The inclusion of HCICO provisions in the LCFS regulation recognizes that some crude oils require additional energy to produce (e.g., bitumen mining or thermally enhanced oil recovery techniques) or emit higher levels of GHG emissions during the production process (e.g., excessive flaring), significantly beyond the average carbon intensity value used in the baseline. A performance-based accounting system is necessary to ensure that additional emissions from California's diesel and gasoline fuel are identified and mitigated. A second goal of the HCICO provision is to provide an incentive for oil producers that could supply higher carbon intensity crudes to California refineries to employ emission reduction measures such as reducing flaring, improving energy efficiency, and using carbon capture and sequestration.

Petroleum refiners in California assert that the current HCICO provisions are overly burdensome to their industry, discriminatory toward sources of crude oil, will increase the potential for global crude-shuffling, which they contend would increase GHG emissions, and would put California refiners at an economic disadvantage to out-of-state refiners. Therefore, they have requested that the CI values for CARBOB and diesel in the Lookup Tables of the current regulation be used, regardless of the type of crude supplies used by a refiner (i.e., no differentiation between the carbon intensities of crude oils).

On the other hand, other stakeholders are equally as adamant that the LCFS should continue to account for increases in lifecycle carbon emissions that could occur if higher-intensity crudes are used to replace existing supplies. They assert that: absent a HCICO provision, increased use of HCICOs would largely offset the emission benefits of increased use of low carbon fuels; ignoring increased emissions from HCICOs would be discriminatory and unfair toward low-carbon fuels treated with full lifecycle accounting; no incentive would exist for oil companies to innovate and improve their upstream practices; and California would be sending an inappropriate environmental signal to other jurisdictions pursuing a similar approach. They also argued that crude shuffling already occurs in the industry and that a performance-based approach treats foreign and domestic producers equally.

At the July 1, 2011, Advisory Panel meeting, staff presented five potential options for addressing HCICO in the LCFS. Representatives of the environmental community and the oil industry also made presentations related to the environmental and economic impacts of excluding or including HCICO provisions in the LCFS. Panelists discussed each of the viewpoints presented, and staff committed to continue working with interested stakeholders on possible regulatory amendments to the HCICO provisions in the current LCFS regulation.

Staff has continued working with stakeholders on regulatory revisions for addressing HCICO, including discussing the various approaches suggested by staff and stakeholders. We have also shared guiding principles for considering HCICO amendments, including: seeking an accurate accounting for emissions from production of crude oil; discouraging potential increases in emissions; promoting innovation for emission-reduction activities; and discouraging the potential for crude shuffling to generate credits, avoid deficits, or otherwise comply with the regulation[116].

Currently, ARB staff has proposed amendments to the HCICO provisions in the LCFS for consideration by the Board at its December hearing. Staff will continue working with stakeholders on possible revisions to staff's current proposal leading up to that Board hearing.

This chapter provides additional background information on the current regulation, including the need to address HCICOs; a brief description of six possible approaches that have come to our attention for addressing HCICOs; and a description of the guiding principles and other criteria for assessment of these approaches to help inform our decision-making process. Staff conducted a preliminary qualitative evaluation of each approach with respect to the guiding principles and included them in this chapter. It should be noted that the primary reason why revisions to the HCICO provisions are being considered is because of the increase in average baseline CI that was not captured by the existing HCICO provisions.

B. Background

1. Regulation Requirements

The regulation requires the following:

a. Basis for Compliance Schedule: The California baseline crude oil mix is used to calculate average Lookup Table values for CARBOB[117] and diesel. Gasoline compliance targets are calculated relative to CI for CaRFG[118] (90% CARBOB and 10% Average Ethanol). Diesel compliance targets are calculated relative to CI for ULSD. [119]

b. Base Deficit: All producers of gasoline (diesel) calculate a "Base" deficit using the difference between the average Lookup Table value for CARBOB (ULSD) and the compliance target in that year.

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[116] See advisory 10-04A for guidance on how to handle HCICO for 2011 and 2012.
[117] California Reformulated Gasoline Blendstock for Oxygenate Blending
[118] California Reformulated Gasoline
[119] Ultra Low Sulfur Diesel

c. Incremental Deficit: An incremental deficit is applied only to those companies which use HCICO from non-baseline sources.[120] HCICO is defined as crude oil with a production and transport CI greater than 15 g/MJ.

d. Promoting Innovation: For HCICO, the average CI values from the Lookup Table may be used if the oil is produced using innovative methods such as CCS or other methods which reduce the CI to less than 15 g/MJ.

2. Summary of Crude Screening Workgroup Process and Progress

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

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

The draft screening process was applied with the assistance of CEC staff to approximately 250 crude sources, of which approximately 80 percent were identified as non-HCICO. A list of marketable crude oil names was evaluated and a list of non-HCICOs was created. The remaining sources which are designated as potential-HCICO are those produced using thermal recovery methods, bitumen mining, excessive flaring, or upgrading.

3. Regulatory Advisory 10-04A

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

[120] A baseline crude source is a location which contributed two percent or more of the total crude oil refined in CA in the year 2006. These locations are California, Alaska, Saudi Arabia, Ecuador, Iraq, Brazil, Mexico, and Angola.

implementation of the LCFS in 2011. Two regulatory advisories were issued to provide LCFS implementation guidelines that included clarifications related to HCICO provision, amongst others.

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

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

C. Potential Approaches for Regulation Amendments

This section outlines six potential approaches to the treatment of HCICOs in the LCFS regulation. These approaches are a combination of those suggested by stakeholders and/or identified by ARB staff. These approaches were presented at a workshop and comments were requested from the stakeholders. The comments received are posted at http://www.arb.ca.gov/fuels/lcfs/hcicocomments.htm

1. Current Approach with Modifications

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

- Include a screening process to codify the method used to generate the non-HCICO list. The method will be presented as a certification process allowing for Executive Officer approval of additions to the non-HCICO list.

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

- Include language which sets an interim default HCICO CI for non-baseline crudes that are not on the non-HCICO list.

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

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

2. California Average Approach

This is the approach being proposed to the Board on December 16, 2011. The base deficit is calculated the same as in the current approach. However, an incremental deficit is applied to all companies if the average crude slate refined in California becomes more carbon intensive over time. The application allows for "the industry as a whole" to shift its crude slate and not be penalized as long as the average CI of the California crude slate does not increase over time relative to the baseline year.

- <u>Base Deficit:</u> All producers of gasoline (diesel) will calculate a "Base" deficit using the difference between the average Lookup Table value for CARBOB (ULSD) and the compliance target in that year. This calculation is the same as currently in the regulation on page 52 and will be the same for each company regardless of their own crude slate.

- <u>California Average Incremental Deficit:</u> For the California crude refining industry:

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

    - If the "current" California average CI is greater than the "baseline" California average CI, then all companies will incur an incremental deficit calculated using the difference between the current CI and the baseline CI.

    - An individual company can earn credits if it purchases crude from sources that have implemented innovative methods such as CCS to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

A variation of this approach provides the regulated parties option to report company specific CI values through an approach analogous to the Hybrid Approach B (see option 3 discussed below) instead of being subject to the California average CI value in a given year. Those companies opting to report company specific CIs would be excluded from the California average CI calculation for that year. Any credit generation opportunities would be premised on a company choosing to report their own company specific baseline.

3. Hybrid California Average/Company Specific Approach

The base deficit for individual companies is calculated the same as in the current approach. However, individual companies only incur an incremental deficit if their own crude slate becomes more carbon intensive over time relative to their crude slate refined in the baseline year. The calculation allows for individual companies to shift the crude slate they refine in California and not be penalized as long as the average CI of their own crude slate does not increase.

- <u>Base Deficit:</u> All producers of gasoline (diesel) will calculate a "Base" deficit using the difference between the average Lookup Table value for CARBOB (ULSD) and the compliance target in that year. This calculation is the same as currently in the regulation on page 52 and will be the same for each company regardless of their own crude slate.

- <u>Company-Specific Incremental Deficit (Approach A):</u> For each oil company:

    - A "baseline" volume of HCICO would be determined using the crude slate refined by that company in CA during the baseline year.

    - Each year of the regulation, a "current" volume of HCICO would be calculated using the crude slate refined by that company in CA during a prior year.

    - If the company's "current" volume of HCICO is greater than its "baseline" volume of HCICO, then the company will incur an incremental deficit calculated using the difference between the current volume and the baseline volume.

    - An individual company can earn credits if it purchases crude from sources that have implemented innovative methods such as CCS to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

- <u>Company-Specific Incremental Deficit (Approach B):</u> For each oil company:

    - A "baseline" CI value would be calculated using the crude slate refined by that company in CA during the baseline year.

    - Each year of the regulation, a "current" CI would be calculated using the crude slate refined by that company in CA during a prior year.

- If the “current” company-specific CI is greater than the “baseline” company-specific CI, then the company will incur an incremental deficit calculated using the difference between its current CI and its baseline CI.

- An individual company can earn credits if it purchases crude from sources that have implemented innovative methods such as CCS to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

4. Company Specific Approach

Each oil company will have distinct Lookup Table values and compliance targets for gasoline and diesel which are based on the crude slate refined by that company in California in the baseline year. Individual companies only incur an incremental deficit if their own crude slate becomes more carbon intensive over time. The approach allows for individual companies to shift their crude slates and not be penalized as long as the average CI of their own crude slate does not increase.

- Company-Specific Base Deficit: Each producer of gasoline (diesel) will calculate a “Base” deficit using the difference between their average Lookup Table value for CARBOB (ULSD) and their compliance target in that year.

- Company-Specific Incremental Deficit: For each oil company:

    - Each year of the regulation, a “current” CI would be calculated using the crude slate refined by that company in CA during a prior year.

    - If the “current” company-specific CI is greater than the “baseline” company-specific CI, then the company will incur an incremental deficit calculated using the difference between its current CI and its baseline CI.

    - An individual company can earn credits if it purchases crude from sources that have implemented innovative methods such as CCS to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

5. Worldwide Average Approach

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

- Worldwide Average Base Deficit: All producers of gasoline (diesel) will calculate a “Base” deficit using the difference between the average Lookup Table value for CARBOB (ULSD) and the compliance target in that year.

- Worldwide Average Incremental Deficit:

  - Each year of the regulation, a “current” worldwide average CI would be calculated using the crude slate produced and refined worldwide during the previous year.

  - If the “current” worldwide average CI is greater than the “baseline” worldwide average CI, then all companies will incur an incremental deficit calculated using the difference between the current CI and the baseline CI.

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

6. California Baseline Approach

All gasoline and diesel fuels use the existing CI values in the Look-Up Table. When reporting, refiners will only calculate and be subject to the Base Deficit for all refined products regardless of crude. The Look-Up Table values for gasoline and diesel would not be updated.

D. Assessment of Potential Approaches for Regulation Amendments

ARB staff are considering and evaluating the potential approaches for regulatory amendments or revisions. Staff’s intention is to recommend the hybrid California average/company specific approach to the Board on December 16, 2011 as a proposed regulatory revision. The guiding principles that form the basis for our assessment of the alternatives are outlined below. These principles ensure that the core objectives of the HCICO provision are achieved.

1. Key Guiding Principles

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

- *Discouraging potential increases in emissions:* An incremental deficit for backsliding with respect to the baseline will ensure that the GHG emission contributions from the petroleum sector do not increase over time.

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

- *Discouraging potential for crude shuffling to generate credits, avoid deficits, or otherwise comply with the regulation:* Providing flexibility to choose crude oils based on a performance metric will minimize potential carbon leakage out of California. Additionally, a program design that can be exported to other jurisdictions will result in minimizing such leakages as other jurisdictions adopt consistent programs.

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

E. Summary and Conclusions

The Panel focused on the bigger issues relate to HCICO, including discussing if the HCICO provision is achieving its objective; if modification to the provision is needed; and encouraged staff to develop a set of principles to guide us through alternative proposals. Although most panelists agreed that the current provisions needed modifications, there were a wide range of opinions on what those modifications should include. Staff will continue working with stakeholders on this important issue and will workshop proposed regulatory amendments. In addition, it should be noted that staff commits to performing economic and environmental analyses related to any regulatory amendments that we propose. Staff will be proposing the California average approach to the Board on December 16, 2011.

X. LCFS Credit Market

A. Introduction

This chapter was developed with input from interested Advisory Panel members who formed the Credit Market Subgroup with ARB staff. The chapter begins with background information on the existing LCFS regulatory requirements with respect to credit trading. It then discusses the staff's upcoming proposed amendments that would establish formal provisions governing credit trading at this early stage of the program.

The subgroup weighed in on the need to get formal rules in place to govern credit trades, provide certainty in trades, and establish procedures for ensuring the transparency of the credit market. The proposed amendments, developed with the subgroup and Panel's input, are needed at this time in order to establish the LCFS credit market, which is in its infancy. Staff is proposing these changes with an eye toward refining the provisions in the future to maximize the credit program's utility and effectiveness.

With Panel members' feedback from their experiences interfacing with similar programs, the chapter then discusses other credit trading programs, including any lessons learned from those programs. Such lessons would hopefully help inform future iterations of the credit trading provisions. Finally, the chapter discusses key design themes suggested by panelists for staff's consideration when designing the next-generation credit trading system for the LCFS.

The Panel's perspectives on what makes a robust credit trading system will help to inform recommendations on regulatory provisions and tools that ARB staff develops for the Board's consideration.

1. Current LCFS Regulation

A key feature of the LCFS program is that it allows regulated parties to generate, bank, and trade LCFS credits. Regulated parties generate credits by selling fuel in their fuel pool with carbon intensity that is lower than the applicable CI standard. Conversely, selling fuel with carbon intensity that is higher than the applicable CI standard results in deficits.

While the current regulation establishes a market for LCFS credits, it does not specify provisions that govern credit transactions between regulated parties. Nor does the current regulation specify a mechanism for tracking and reporting of information related to the accrual and disposition of credits. New regulatory provisions will be needed to set the ground rules governing credit trading. Further, tracking these transactions will require the establishment or expansion of tools that the ARB is developing.

Because implementation of the CI standards recently began in 2011 and regulated parties are already generating credits, it is imperative that specific provisions be developed in the near-term to set the ground rules for credit trading. To this end, the staff's upcoming proposed amendments would provide such ground rules, which are discussed in more detail below.

2. *Proposed LCFS Amendments for December 2011 Rulemaking*

Currently, credit banking, trading and retirement provisions will be released for a formal public review at the end of October 2011 as proposed amendments to the LCFS regulation. Those proposed changes will be considered by the Board at its December 2011 hearing. The proposed amendments will provide the initial set up of the LCFS credit market, which is necessary to establish a reliable, sustainable and transparent credit market. The changes will help ensure transparency and utility to the credit market participants by providing key transactional information in a publicly-available format.

The proposed regulatory amendments will address:

- The generation and acquisition of transferable credits;
- The acquisition of carry-back credits to meet the annual compliance obligation;
- Credit transfers and the required information that ARB will need to receive;
- The retirement of credits at the end of the compliance period; and
- The disclosure to the public of credit market activity.

The following provides an overview of the main credit trading-related provisions in the upcoming proposed amendments.

a. *Establishes How Credits Are Banked and Traded within the LCFS Program*

Proposed changes to section 95484(b) and new section 95488(b) would provide the language describing how a credit is generated, banked and then made available for trade. Generation and banking is dependent upon the submission of a quarterly report before the credit can be placed into a regulated party's bank. Once that credit is in the bank, the regulated party would be free to sell that credit to another regulated party upon ARB's confirmation of the transaction.

b. *Specifies How Credit Balances Are Calculated and Banked for Each Reporting Quarter*

The proposed amendments will separate the generation of credits and deficits throughout the quarter and year, making credits fungible as soon as they are generated upon submittal of a quarterly report. As noted, at the end of each quarter, regulated parties will submit their progress reports. Fuel transactions within each quarter will be recorded; credits will be generated for those fuels that have a CI lower than the applicable standard, while deficits will be generated for those fuels with a CI higher than the applicable standards. Once credits are generated and recorded, the regulated parties will be free to trade these credits (upon ARB confirmation), use them to reconcile deficits, or simply bank them for later use.

c. Specifies Reporting Requirements for Trades and the Process for Reporting to ARB

The proposed amendments include a requirement for regulated parties to use a specified credit transfer form to account for the trading that will occur between regulated parties. The form currently includes information about the seller and buyer as well as the volume of credits exchanged and their price of the transaction. For tracking purposes, ARB staff is exploring the concept of applying unique identifiers (IDs) to credits that are proposed to be traded. There are a number of reasons why having unique IDs can be useful, including providing ARB with the ability to track fraudulent credits back to the originator. Unique IDs may also enable ARB to determine whether there are any trends embedded in credit transactions (e.g., if regulated parties are preferentially purchasing or retiring certain types of credits and why). If ARB develops such an ID system for LCFS credits, the proposed amendments would require the transfer form to record the applicable IDs for the credits involved.

d. Sets Forth Provisions for Credit Carry-Back and Credit Retirement Hierarchy

The proposed amendments include a provision to allow regulated parties to buy credits under specified conditions and apply them retroactively to address a deficit in the prior year (i.e., buy credits to "carry back"). In other words, a regulated party, facing a deficit in a compliance year, would be allowed to purchase, within the first three months of the next compliance year, existing credits that can be "carried-back" to the prior compliance year with the deficit.

Another proposed provision would address the retirement of credits to reconcile a deficit. That is, when a regulated party needs to retire a banked credit, it may have a number of credits in its bank that, for whatever reason, the regulated party wants to retire in a certain order. Because of this, the proposed amendments would require a regulated party to specify its preferred retirement hierarchy when it comes time to retire a set of credits. Failure to specify such a hierarchy would incur no penalty for a regulated party; the proposed amendments would simply retire the desired number of credits in a specified default order.

e. Requires ARB Publication of Market Information

To provide useful information to market participants, the proposed amendments would require ARB staff to publish separate reports on information related to the credit market on a monthly and quarterly basis, with the option to report more frequently if ARB staff deems it appropriate and feasible. Information to be published would include transaction prices, volumes of credit bought/sold, total credits and deficits for specified periods, and other relevant information, all presented in aggregated, averaged, or other forms that would provide useful information without compromising confidential business information.

3. Lessons Learned from Other Credit Trading Programs

To help inform further development of the LCFS credit market, staff and interested panelists reviewed three other credit-based trading programs to determine if they yielded useful "lessons learned." These were the South Coast Air Quality Management District's Regional Clean Air Market (RECLAIM), the ARB's own cap-and-trade program, and the federal Renewable Fuel Standard (RFS1/2).

RECLAIM is one of the earliest models for a credit-based system to address stationary source emissions. The RECLAIM program caps the total emissions inventory of the regulated sources, and then decreases the cap over time to reduce emissions. The local district program allows affected parties to market emission reductions amongst themselves. In general, RECLAIM proved to be successful in reducing emissions of SOx and NOx by allowing compliance flexibility, relative to the existing prescriptive regulations, and thereby lowering compliance cost. One important lesson learned from RECLAIM is the utility of real-time publication of transactional information, which enables market participants to better gauge an appropriate value for a credit when negotiating its fair market value.

ARB's cap and trade program controls GHGs from major emission sources ("covered entities") by setting a firm limit (the "cap") on GHG emissions while employing market mechanisms to cost effectively achieve the emission reduction goals. The cap for GHG emissions from covered sources would commence in 2013 and decline over time, achieving emissions reductions throughout the program's duration. The cap is measured in metric tons of carbon dioxide equivalent (MTCO2e). Covered entities will be able to buy permits to emit (allowances) at auction, purchase allowances from others, or purchase offset credits (the "trade"). The cap-and-trade program would establish the total amount of GHG emissions that covered sources would be allowed (permitted) to emit. ARB would distribute allowances to emit GHGs, and the total number of allowances created would be equal to the total amount ("aggregate cap") set for cumulative emissions from all covered entities. Each allowance would permit the holder to emit one MTCO2e of GHG.

The cap and trade program shares many design features with the LCFS. As such, experiences with cap and trade should prove useful in informing further development of the LCFS credit trading program. However, given that the Board just adopted the cap and trade program in late October 2011, it is far too early to glean any parallels and lessons from the ARB's cap and trade experience. However, we have learned that the complexity of the market is greatly increased when secondary markets are involved.

Finally, the RFS uses the same concept of tradable credits to promote the use of renewable fuels. However, this program reduces GHG emissions by mandating specific volumes of renewable fuels, as the control mechanism, versus directly controlling carbon emissions like the LCFS. Experience drawn from this federal program supports the use of unique IDs known as “renewable identification number” (RIN) to track renewable fuel volumes.

Nonetheless, U.S. EPA’s use of unique IDs under RFS2 has evolved over time and the use of unique IDs under RFS has not been without issues. The U.S. EPA found that the use of unique IDs added unnecessary complexity by requiring the regulated community to track their own unique IDs. The U.S. EPA found that the program functioned optimally by taking on the responsibility of generating unique IDs themselves and for internal purposes.

Another insight drawn from the RFS program relates to the generation of RINs. Under the current RFS2 program, parties are allowed to generate and market credits on their own; however, a recent review of generated RINs has revealed fraudulent activity by parties generating RINs that are not associated with a renewable fuel volume (i.e., basically, fake credits). Because of the discovery of fraudulent activity, ARB staff has proposed changes that would place ARB in the middle of a credit transaction (i.e., to complete the “handshake” between the buyer and seller). As a result, ARB is in a position to monitor the generation of credits available for trade, thereby increasing market confidence in the validity of credits circulating in the program.

B. Framework for Further Development of a Credit Market

1. Overview

Under the LCFS, regulated parties are required to meet the applicable carbon intensity standards for fuels they produce or market. Their ability to meet the standards depends on the fuel mix produced or sold by the regulated party and whether there are LCFS credits available for purchase if needed. As noted, regulated parties generate credits when their fuels have a carbon intensity that is lower than the standard, deficits when their fuels have a carbon intensity that is higher than the standard. Over time, the standards are set to become more stringent, and the ability to purchase credits from those who have over-complied will become increasingly important as one way to help meet the standards.

A functional, valid and secure credit market is crucial to the development and sustainability of the LCFS program. To facilitate credit trades, especially in the later years, the program needs to include a clear and well-established trading mechanism. Further, the credit market should provide a secure arena for exchange and purchase of carbon reduction credits. An efficient and secure market will incentivize regulated parties to strive for the maximization of credit generation and a return on their investment, while providing the necessary assurances for long-term investing. The structure of the market is important and should contain checks and balances to ensure the validity of credits being exchanged, as well as providing the market with basic economic information (e.g., credit process, volume, price per transaction, etc.) for investors and other regulated parties to be well informed.

Panelists have suggested that further development of the credit market, beyond staff's proposed amendments for the December 2011 hearing, should be focused on near-; mid-, and long-term goals to maximize the overall achievement of the LCFS program. In the near-term, staff has been focused on developing a manual system to account for transactions that may occur in 2011 and 2012; meanwhile, an automated system is being developed for future use. A credit market subgroup, consisting of Advisory Panel review members, was also been formed to review strategies and to provide input on the development of the credit market structure and market transparency.

In the mid-term, staff will develop a new reporting tool designed with increased functionality to account for credit generation, as well as regulated party transfers of credits. The LCFS Central Information System (L-CIS), the next generation LCFS Reporting Tool under development, will eventually serve as an information hub for regulated parties to submit their LCFS required documentation. At the onset of the credit trading program, ARB will maintain the lead role in development of the market structure, first through tracking of trades through the existing LCFS Reporting Tool. Then, ARB will design and work through the L-CIS to ensure the validity of market transactions. Staff is evaluating, in consultation with stakeholders, various features for possible incorporation into the L-CIS, including near real-time reporting of credit transaction prices, volumes traded, and other information that can be useful to a robust trading market. Panelists expressed strong support for the L-CIS development, conveying a sense of urgency for sooner electronic implementation.

Market growth and detailed information about credit transactions in the short- to mid-term will instruct ARB and the public on how well the credit market is functioning. As discussed below, some panelists have suggested the use of a third party service to handle transactions. The ARB staff's analysis of the functioning of the market will help ascertain whether a third party entity is necessary for that purpose.

For the mid- to long-term, ARB staff will investigate the feasibility of making the LCFS market accessible to the secondary market (i.e., persons who are not regulated parties, which would include brokers, speculators, and other "willing participants"). If the decision is made to open the LCFS credit market to the secondary market, staff would need to evaluate the L-CIS technology and update it accordingly.

2. Key Design Considerations for a Robust Trading System

a. Role of the Market

Panelists have noted that the role of the carbon credit market is to facilitate the purchase, sale, and retirement of actual GHG emission reductions. The market's supportive role is to facilitate impartial good faith business transactions.

A secondary effect of an effective and well-functioning market for LCFS credit exchanges would support efficient deployment of capital to developing and deploying the most viable and least cost low-carbon fuel options. In turn, the lowest cost for LCFS compliance should come to the forefront.

b. Role of ARB

Some panelists have suggested that the appropriate role for ARB vis-à-vis the LCFS market is to create and manage the inner workings of the credit market, but likewise strive not to unduly influence the market by providing a hands-off approach to individual transactions. The ARB should be unnoticeable during day-to-day credit trading. Under this vision, the ARB would merely act as a "credit banker" that would account for all transactions and inform the public of general market information.

In order to establish a smoothly functioning market for credit exchanges, the ARB will need to establish the structure and rules that ensure appropriate availability of information regarding credit transactions. There are a number of options for how credit transactions could occur, including:

- Option 1: ARB requires regulated parties to report all credit buying and selling transactions. The ARB publishes only general market indicator information.
- Option 2: ARB requires that authorized third parties conduct all credit buying and selling transactions. Either the ARB or the authorized third parties publish general market indicators.
- Option 3: ARB requires that all buying and selling transactions be conducted through the ARB. The ARB publishes appropriate market indicator information.

As noted previously, staff's upcoming proposed amendments would follow Option 3. The benefits of this option are that ARB has the chance to evaluate credit transactions and to ensure the validity of the credits being exchanged, which is problematic with Option 1. Eventually, the transactions will also be incorporated into the L-CIS system, where both day-to-day transactions and routine reporting will be managed. As the credit market expands, ARB may consider independent and authorized third party entities to oversee the credit market. But the enforcement mechanisms and liability provisions, among other considerations, would need to be evaluated carefully before third-party credit exchanges and brokerages can be developed.

c. Transparency

Another important topic that was raised by panelists is the need to provide the market with sufficient transparency. Publication of market-transaction information should be provided on a timely basis. For the LCFS, public availability of appropriate credit transaction information will enable more-informed business and investor decision-making. However, the need for transparent information must be balanced by the need to protect confidential business information and other information that is protected from disclosure.

Market awareness of transaction details such as price, volume, and timing of credit trades, will help inform market participants in their understanding of market valuations. Beyond the necessary market information, other data that is prohibited from disclosure under State law will remain strictly confidential. The information may include, but not limited to, the identity of parties to a transaction and the amount of credits any one party may have in its account at a given time. Panelists suggested that the types of information related to a credit market, which need to be collected or published, depending on the nature of the information, include the following:

Information needed by ARB to determine the health of the credit market:

- A list of all buyers in the market
- A list of all sellers in the market
- Credit prices
- Amount of credits circulating in the market
- Feedstock/fuel type

Information to be made available to the public:

- Credit price range
- Average credit prices and trends
- Credit sales/traded volumes

Information that may be claimed confidential:

- Buyer and seller identification
- Specific feedstocks used in generating the credits

d. Ensuring Credit Trading is a Competitive Exchange

The most effective method for ensuring that credit trading is a competitive exchange is to maintain a clear and transparent trading system, which is free of fraudulent activity. As credit traders develop confidence in and feel comfortable with the accuracy, validity and relative speed of transactions, the carbon reduction credit market will evolve to operate similar to other well-established markets.

Panelists from the Credit market subgroup have suggested that the LRT subgroup, which helped develop the existing reporting tool, be reformed to provide input toward the development of the next generation L-CIS. Panelists have also suggested that use of third party marketers would potentially increase the volume and transactions that occur. However, with the current market structure and the limited number of regulated parties involved, this option may not provide the best approach at the current time.

It has also been recommended by some panelists to make the market accessible to parties outside the program. In theory, the opening of the LCFS to the secondary market would infuse additional capital into the market by bringing in "willing participants" beyond those parties that are required to participate as regulated parties. As noted above, the LCFS program is in its infancy, and it is premature to develop this concept at this time, particularly given that additional ARB resources that would likely be needed to track and enforce such a broad expansion of the LCFS market. However, if this concept is pursued by ARB in the future, a “trigger” of some sort may be needed to limit the potential for a party to corner the market (i.e., establish a holding limit for credits). This trigger would alert the market if an outside party has a substantial holding of credits but is not trying to maintain compliance through the holding of obligated fuels. ARB staff will continue to evaluate this concept.

e. Protection from Fraudulent Use of the System

To assure a secure credit market, panelists have remarked that ARB must employ a zero tolerance policy against fraudulent activity. To this end, measures can be developed to provide protections against fraud. For example, routine auditing of suspect transactions may yield invalid transactions. Evaluation of credit pricing or unexplained price spikes may be investigated to rule out impropriety. Selected sampling and data mining may also yield valuable information that can root out fraudulent transactions.

As an added option, ARB staff is considering assigning unique identification numbers to all credits generated. These unique IDs would allow for a comprehensive auditing capability. This idea would need to be evaluated in detail as part of the L-CIS development. Implementing such identifiers would likely necessitate sufficient software development to handle the process and ensure that recording and reporting the ID information do not become burdensome on the regulated parties.[121] Some panelists have expressed support for harmonization with existing ID reporting software.

The ARB staff believes there is merit in using unique credit IDs (whether they are for external or internal use) because of the benefits they can provide to the sellers and buyers of credits. These potential benefits include elimination of fraudulent credits; credits being claimed by multiple parties; tracking the movement of credits within the market; and identifying the market variability of credits being exchanged through regulated parties.

f. Ensuring Longevity and Robustness in the Credit Trading Market

Some panelists have noted that the credit market has been established to facilitate compliance with the LCFS. A major benefit of the credit market is to provide alternative compliance options during the fuel industry’s transition towards lower carbon intense fuels. If the credit market functions as designed and compliance with the carbon intensity factors is attained, then the purpose of the credit market may shift, from

[121] The staff’s upcoming proposed amendments would allow, but not require, the development of unique credit identifiers; if such unique identifiers are implemented, the proposed amendments would require credit buyers and sellers to record the identifiers in the credit transfer form covering the credits that are to be traded.

obtaining lower carbon emissions in the fuels mix through 2020, to maintaining compliance for the years after 2020.

C. Conclusions and Summary of Panel Findings

Staff's current rulemaking efforts will provide the necessary regulation provisions to enact an effective credit market at this initial stage of the program. The credit market is a necessary component of the LCFS regulation and provides regulated parties with options for how they will comply with the carbon intensity standards. The ARB's role at this time is to provide the market structure, administration and validation for a secure and effective carbon reduction credit trading system. Over time, ARB will further develop electronic systems to administer the credit market and to improve reliability, performance and security. Additional roles for ARB in the credit market need to be explored.

After discussions with panelists, staff identified a number of key aspects that must be present for a functioning credit market. First, the credit market must be transparent so all parties involved have a clear understanding of the market process and that there is no distinct advantage for one regulated party compared to another. Second, the market must be competitive and active to encourage trade amongst the parties otherwise the market will not survive. Third, ARB needs to have oversight on the market to assure market stability in both the near and long-term. Fourth, ARB should play a key oversight and monitoring role to guard against market manipulation and fraud.

Staff determined that a number of observations and suggestions by panel members were useful in informing the staff's upcoming proposed amendments for the December 2011 hearing. As noted above, other suggestions by the panelists merit further investigation for possible development and implementation in future iterations of the credit trading provisions.

Appendix A. Compliance Schedules for Gasoline and Diesel

Table A-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%

Table A-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%

Source: Adapted from Title 17, California Code of Regulations, section 95482

Biofuel Feedstocks

- Corn ethanol: Assumptions reflected three categories: 1) Midwest corn ethanol, with a carbon intensity close to CARBOB; 2) California corn ethanol produced in the latest generation of plants, with a carbon intensity about 15 percent below that of CARBOB; and 3) ethanol meeting the performance standard specified in the 2007 EISA: a 20 percent carbon intensity reduction over CARBOB;

- For each gasoline-related scenario, Midwest corn ethanol volumes diminish but 300 million gallons of California lower-CI ethanol remain available in the California market through 2020;

- Other biofuels: 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.

  Assumption Review

The initial assumption—that lower-CI ethanol would play a role in overall LCFS compliance—appears to be valid, although not in the manner that staff had anticipated. Based on reporting data received through the LCFS reporting tool (LRT) for the first two quarters of 2011, regulated parties have documented about 100 million gallons of lower-CI corn ethanol use. If this usage continues through the rest of 2011, the volume of lower-CI corn ethanol will far exceed the 2009 estimates.

What was not expected in 2009 was the number of Method 2A/2B pathways for corn ethanol that would be available for use. As shown in Table B-1, several new pathways were developed for corn ethanol, especially for ethanol with a CI of 90 or lower. It now appears that ethanol will be produced under more pathways than originally envisioned. The table shows the number of new pathways compared to 2009, which grew from 13 to 56 for corn ethanol, most of them Midwest corn ethanol plants that have made efficiency improvements and/or diversified feedstocks.

Table B-1. Comparison of 2009 versus 2011 pathways for Corn Ethanol

Carbon Intensity	2009	2011
CI>95	5	5
90<CI<95	3	11
85<CI<90	2	15
80<CI<85	2	16
CI<80	1	9
Totals	13	56

Brazilian sugarcane ethanol has just recently arrived in California, although not yet in any significant volume. Our 2009 scenarios, 2011 scenarios, and 2011 scenarios developed by the California Energy Commission (CEC) show Brazilian sugarcane ethanol potentially playing a key compliance role in the next several years, although at some marginal cost.

Commercial cellulosic ethanol is not yet into the commercial production phase. Additional technological developments and cost reductions are necessary for cellulosic ethanol to be produced in appreciable volumes. As mentioned above, EIA estimates are much less than the original RFS2 volumes, so staff has updated the illustrative compliance scenarios, taking the new projections into account. Future implementation assessments will require the monitoring of cellulosic and renewable ethanol production capacity over time; however, inclusion of cellulosic ethanol in the 2011 scenarios is still appropriate. Additional discussion on the state of development for cellulosic ethanol can be found in Chapter IV.

Sufficient quantities of biodiesel feedstocks exist for the production volumes necessary for the market. California supplies of biodiesel are significantly lower than prior years due mainly to the removal of a 2009 federal blenders' tax credit. (It was later restored, but is expected to sunset at the end of 2011.) Excess biodiesel production capacity exists to meet potential future incremental demand. Staff anticipates that biodiesel will play an increasing role throughout the compliance schedule and would be appropriate to consider under the 2011 scenarios.

<u>Advanced Vehicle Fleets</u>

- 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 (ZEV) 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 ZEV regulation[122].

Assumption Review

In 2009, staff ran illustrative compliance scenarios with a wide range of advanced-technology vehicles on the road in 2020: 560,000, 1 million, and 2 million. For the 2011 scenarios, staff used 580,000 vehicles for all scenarios, which reflects ARB's most current estimate. The annual ramp-up to the 2020 totals was largely the same between 2009 and 2011.

Carbon Intensity of Electricity

In 2009, staff estimated the carbon intensity of electricity based on the California marginal electricity mix, which is a combination of natural-gas combustion equipment: boilers, simple-cycle turbines, and combined-cycle turbines. The average CI for California marginal electricity is estimated at 104.71 gCO_2e/MJ.

Assumption Review

For 2011, staff did not change the CI for marginal electricity. Staff will revisit the grid-average and marginal electricity CI values as the 33 percent Renewable Portfolio Standard takes effect.

Gasoline and Diesel Fuel

For the 2009 analysis, the LCFS baseline for the gasoline and related fuels standard was based on E10 (90 percent CARBOB and 10 percent average corn ethanol [95.85 CI]) expected in 2010. Staff assumed an annual VMT growth rate of 1.5 percent for gasoline motor vehicles. Staff adjusted the amount of fuel consumed to reflect the implementation of ARB's Pavley standards for light-duty vehicles, which resulted 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 based on diesel volumes expected in 2010. Staff assumed about a 2.2 percent annual increase in VMT for diesel fuel between 2010 and 2020.

Assumption Review

For 2009, staff estimated the gasoline demand to be 15.4 billion gallons (BG) in 2010 dropping to about 13 BG in 2020. For the 2011 analysis, staff estimated the gasoline demand to be 15.0 BG in 2010 dropping to 12.3 BG in 2020.

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[122] ARB Staff plans to update the ZEV regulation in 2012. For more information go to http://www.arb.ca.gov/msprog/zevprog/zevprog.htm.

For 2009, staff estimated diesel demand at 4.4 BG and 5.4 BG for 2010 and 2020, respectively. For the 2011 analysis, staff used 3.3 BG and 4.0 for 2010 and 2020, respectively. Both the gasoline and diesel demand figures used for the 2011 analysis are consistent with CEC's "Low Petroleum Demand" scenario in their 2011 Integrated Energy Policy Report (IEPR).

Credit Trading

For each scenario in the 2009 analysis, staff assumed that the regulated parties achieved compliance strictly through the purchase and use of lower-CI fuels. There was no banking of credits assumed – that is, all credits were assumed to be used in the year that they are generated.

Assumption Review

For the 2011 analysis, staff assumed some level of over-compliance in the first few years of implementation so that excess credits are generated for later compliance demonstrations. LRT data for the first two quarters of 2011 bear out this assumption: regulated parties are generating and banking substantial quantities of LCFS credits, presumably for later use in complying with the standards as they become more stringent.

Appendix C. Summary of Gasoline and Diesel Illustrative Scenarios

The purpose of these illustrative scenarios is directly related to the 2011 Low Carbon Fuel Standard (LCFS) program review, which is required by the regulation and due to the Board no later than January 1, 2012. Specifically, the regulation requires an assessment of the need to adjust the compliance schedule, as well as an economic assessment of the LCFS, for which these scenarios will inform. These illustrative scenarios are not projections, but plausible pathways to compliance based on a series of assumptions, which are clearly outlined below.

Assumptions Common to All Gasoline Scenarios

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH CI	87.8	84.7	81.6	79.0	76.6	74.3	72.0	69.9	67.9	66.0
Cane EtOH CI	73.4	72.0	71.0	70.0	69.0	68.0	67.0	66.0	65.0	64.0
Cellulosic CI	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Drop-In CI	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Avg. % EtOH of Gasoline (Scenarios 1-8)	10.0	10.0	10.0	10.0	10.0	13.5	13.7	13.9	14.2	14.5
Avg. % EtOH of Gasoline (Scenarios 9-11)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
No. of FCVs (1,000s)	0.9	2.0	3.0	4.0	10.0	15.0	20.0	22.943	29.158	39.783
No. PHEVs (1,000s)	0.5	20.0	45.0	70.0	110	150	200	261.259	336.522	425.618
No. of BEVs (1,000s)	3.0	5.0	7.0	9.0	20.0	30.0	40.0	53.873	81.123	118.795

Scenario 1 - CA gets about 85% of EIA cellulosic projections; low corn EtOH use in 2016 and after; large FFV use using EtOH 50% of the time; substantial early surplus credit generation before 2017; annual deficits generated between 2017 and 2020, but some credits remain after 2020.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.40	1.27	1.05	0.51	0.22	0.14	0.10	0.06	0
Cane EtOH (bgal)	0	0.08	0.18	0.40	0.80	1.55	1.52	1.44	1.27	0.76
Cellulosic (bgal)	0	0.01	0.04	0.07	0.24	0.39	0.61	0.95	1.44	2.16
FFVs (1,000s)	0	50	100	200	300	500	900	1,400	2,200	2,700
% time E85	50	50	50	50	50	50	50	60	60	60
Total EtOH (bgal)	1.50	1.52	1.53	1.56	1.58	2.16	2.28	2.49	2.77	2.92
Total E85 (bgal)	0	0.02	0.04	0.08	0.11	0.18	0.33	0.59	0.92	1.10
Total CARBOB (bgal)	13.5	13.5	13.5	13.5	13.3	12.8	12.6	12.4	12.1	11.9
Avg.% EtOH	10.0	10.1	10.2	10.4	10.6	14.4	15.3	16.7	18.6	19.8
An. Credits (1,000s MT)	556	714	550	410	131	827	-181	-599	-305	-267
Cum. Credits (1,000s MT)	556	1,270	1,820	2,230	2,361	3,188	3,007	2,408	2,103	1,836

Scenario 2 - CA gets nearly all (about 90 percent) of EIA cellulosic projections between 2011 and 2020; low sugar cane EtOH use and low corn EtOH use in 2020; relatively low FFV use using E85 about 50% of the time before 2018 and about 60% of the time after; substantial early surplus credit generation before 2017; annual deficits generated between 2017 and 2020, but some surplus credits remain after 2020.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.48	1.41	1.35	1.10	1.28	0.93	0.40	0.07	0
Cane EtOH (bgal)	0	0.01	0.03	0.05	0.16	0.32	0.43	0.67	0.39	0
Cellulosic (bgal)	0	0.018	0.08	0.14	0.32	0.53	0.80	1.16	1.84	2.35
FFVs (1,000s)	0	30	60	120	200	400	500	600	700	810
% time E85	50	50	50	50	50	50	50	60	60	60
Total EtOH (bgal)	1.50	1.51	1.52	1.53	1.58	2.13	2.17	2.23	2.30	2.35
Total E85 (bgal)	0	0.01	0.02	0.04	0.11	0.15	0.18	0.25	0.29	0.33
Total CARBOB (bgal)	13.5	13.5	13.5	13.5	13.3	12.9	12.7	12.5	12.4	12.2
Avg.% EtOH	10.0	10.1	10.1	10.2	10.6	14.2	14.6	15.1	15.6	16.1
An. Credits (1,000s MT)	556	683	577	408	63	725	-118	-587	-171	-1,146
Cum. Credits (1,000s MT)	556	1,239	1,816	2,224	2,287	3,012	2,894	2,307	2,136	990

Scenario 3 - Delayed cellulosic EtOH introduction; mostly corn EtOH used until 2015; increasing sugar cane EtOH use through 2020; CA gets about a third of EIA nationwide cellulosic projection; high FFV use beginning in 2015 using E85 a high percentage of the time; surplus credits accumulate until 2019; deficits generated in 2019 and 2020, but some surplus credits remain after 2020.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.50	1.50	1.60	1.22	1.77	1.67	1.04	0.68	0.36
Cane EtOH (bgal)	0	0	0	0.08	0.61	0.86	1.52	2.11	2.48	2.73
Cellulosic (bgal)	0	0	0	0	0.08	0.11	0.19	0.43	0.63	0.93
FFVs (1,000s)	0	0	0	300	700	1,300	2,500	2,900	3,300	3,800
% time E85	100	100	100	100	100	100	100	100	100	100
Total EtOH (bgal)	1.50	1.50	1.50	1.68	1.90	2.74	3.38	3.57	3.79	4.02
Total E85	0	0	0	0.23	0.53	0.96	1.8	2.1	2.3	2.6
Total CARBOB (bgal)	13.5	13.5	13.5	13.4	13.1	12.5	11.9	11.6	11.4	11.1
Avg.% EtOH	10.0	10.0	10.0	11.2	12.6	18.0	22.1	23.5	24.9	26.6
An. Credits (1,000s MT)	556	572	184	39	-158	378	324	197	-523	-1,389
Cum. Credits (1,000s MT)	556	1,128	1,312	1,351	1,193	1,571	1,895	2,092	1,569	180

Scenario 4 - Only corn and sugar cane EtOH until 2015; high corn and sugar cane EtOH through 2020; cellulosic EtOH introduced in 2015 up to only about a third of EIA nationwide projection for 2020; very high FFV use using E85 100 percent of the time; less surplus credit accumulation before 2019 than in Scenario 3; deficits generated between 2018 and 2020, but some surplus credits remain after 2020.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.44	1.42	1.40	1.14	1.65	1.74	1.78	1.64	1.46
Cane EtOH (bgal)	0	0.08	0.16	0.25	0.53	0.77	1.09	1.45	1.76	2.08
Cellulosic (bgal)	0	0	0	0	0.11	0.15	0.28	0.40	0.60	0.89
FFVs (1,000s)	0	20	125	250	500	1,000	2,000	3,000	3,700	4,600
% time E85	100	100	100	100	100	100	100	100	100	100
Total EtOH (bgal)	1.50	1.52	1.58	1.65	1.78	2.57	3.11	3.63	4.00	4.42
Total E85 (bgal)	0	0.016	0.10	0.19	0.38	0.74	1.45	2.12	2.58	3.14
Total CARBOB (bgal)	13.5	13.5	13.5	13.4	13.2	12.6	12.1	11.6	11.3	10.8
Avg.% EtOH	10.0	10.1	10.5	11.0	11.9	17.0	20.5	23.8	26.1	29.0
An. Credits (1,000s MT)	556	661	406	117	-255	221	-13	-191	-315	-655
Cum. Credits (1,000s MT)	556	1,217	1,623	1,740	1,485	1,706	1,693	1,502	1,187	532

Scenario 5 - Small amounts of cellulosic EtOH begins in 2014; drop-in fuel begins in 2015; cellulosic about 25% of EIA 2020 nation-wide projection; no FFVs; substantial surplus credits in early years; deficits generated between 2018 and 2020, but some surplus credits remain after 2020.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.50	1.50	1.39	1.32	1.70	1.57	1.41	1.23	0.98
Cane EtOH (bgal)	0	0	0	0.06	0.10	0.22	0.30	0.39	0.48	0.54
Cellulosic (bgal)	0	0	0	0.050	0.07	0.10	0.16	0.25	0.38	0.59
Drop-in Fuel (bgal)	0	0	0	0	0.13	0.18	0.37	0.51	0.63	0.78
Total EtOH (bgal)	1.50	1.50	1.50	1.50	1.49	2.02	2.03	2.04	2.08	2.10
Total E85 (bgal)	0	0	0	0	0	0	0	0	0	0
Total CARBOB (bgal)	13.5	13.5	13.5	13.5	13.3	12.8	12.4	12.2	12.0	11.6
Avg.% EtOH	10.0	10.0	10.0	10.0	10.0	13.5	13.7	13.9	14.2	14.5
An. Credits (1,000s MT)	556	572	184	6	-3	289	296	-96	-373	-892
Cum. Credits (1,000s MT)	556	1,128	1,312	1,318	1,315	1,604	1,900	1,804	1,431	539

Scenario 6 - Only corn EtOH is used until 2014; sugar cane EtOH and cellulosic EtOH begin in 2014; drop-in fuel begins in 2015; cellulosic about 40% of EIA 2020 nationwide projection; no FFVs; early credits generated with corn EtOH; compliance is achieved every year up to 2020; surplus credits from early generation remain after 2020.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.50	1.50	1.36	1.17	1.64	1.41	1.19	0.93	0.47
Cane EtOH (bgal)	0	0	0	0.09	0.18	0.22	0.34	0.43	0.54	0.63
Cellulosic (bgal)	0	0	0	0.05	0.14	0.16	0.28	0.43	0.61	1.00
Drop-in Fuel (bgal)	0	0	0	0	0.09	0.12	0.28	0.44	0.57	0.72
Total EtOH (bgal)	1.50	1.50	1.50	1.50	1.49	2.02	2.03	2.04	2.08	2.10
Total E85 (bgal)	0	0	0	0	0	0	0	0	0	0
Total CARBOB (bgal)	13.5	13.5	13.5	13.5	13.3	12.8	12.5	12.2	12.0	11.7
Avg.% EtOH	10.0	10.0	10.0	10.0	10.0	13.5	13.7	13.9	14.2	14.5
An. Credits (1,000s MT)	556	572	184	3	0	-3	4	3	1	5
Cum. Credits (1,000s MT)	556	1,128	1,312	1,315	1,315	1,312	1,316	1,319	1,320	1,325

Scenario 7 - Similar to Scenario 6, but with a small number of FFVs operating on E85 50 percent of the time; early surplus credits remain after 2020.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.50	1.50	1.38	1.22	1.72	1.54	1.40	1.03	0.65
Cane EtOH (bgal)	0	0	0	0.08	0.20	0.24	0.34	0.36	0.61	0.69
Cellulosic (bgal)	0	0	0	0.05	0.11	0.13	0.23	0.38	0.55	0.89
FFVs (1,000s)	0	0	0	0	150	220	280	350	400	500
Drop-in Fuel (bgal)	0	0	0	0	0.10	0.12	0.29	0.44	0.57	0.73
Total EtOH (bgal)	1.50	1.50	1.50	1.50	1.53	2.08	2.11	2.14	2.19	2.23
Total E85 (bgal)	0	0	0	0	0.054	0.076	0.093	0.11	0.13	0.15
Total CARBOB (bgal)	13.5	13.5	13.5	13.5	13.3	12.8	12.5	12.2	11.9	11.6
Avg.% EtOH	10.0	10.0	10.0	10.0	10.3	13.9	14.2	14.5	14.9	15.3
An. Credits (1,000s MT)	556	572	184	0	2	6	2	7	7	4
Cum. Credits (1,000s MT)	556	1,128	1,312	1,312	1,314	1,320	1,322	1,329	1,336	1,340

Scenario 8 - Large number of FFVs operating on E85 50 percent of the time; sugar cane and cellulosic EtOH introduced in 2015; drop-in fuel starts in 2016; cellulosic about 25% of EIA 2020 nation-wide projection; compliance is achieved every year between 2011 and 2020, and early surplus credits are generated as in Scenario 7, which remain after 2020; less drop-in fuel than Scenario 7, but large number of FFVs used so that projected E85 use is in line with CEC projections.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.50	1.50	1.56	1.55	2.03	2.10	2.03	1.73	1.61
Cane EtOH (bgal)	0	0	0	0.05	0.18	0.24	0.40	0.52	0.88	0.98
Cellulosic (bgal)	0	0	0	0.016	0.10	0.14	0.24	0.36	0.48	0.68
FFVs (1,000s)	0	0	0	400	1,200	1,400	2,600	3,300	3,900	4,600
Drop-in Fuel (bgal)	0	0	0	0	0.05	0.05	0.14	0.25	0.35	0.51
Total EtOH (bgal)	1.50	1.50	1.50	1.62	1.84	2.41	2.73	2.91	3.09	3.26
Total E85 (bgal)	0	0	0	0.15	0.45	0.52	0.94	1.17	1.36	1.57
Total CARBOB (bgal)	13.5	13.5	13.5	13.4	13.1	12.6	12.2	11.8	11.6	11.1
Avg.% EtOH	10.0	10.0	10.0	10.8	12.3	16.0	18.2	19.4	20.6	21.9
An. Credits (1,000s MT)	556	572	184	4	7	5	2	1	-1	1
Cum. Credits (1,000s MT)	556	1,128	1,312	1,316	1,323	1,328	1,330	1,331	1,330	1,331
An. Credits (New Schedule)	556	572	178	-2	11	56	86	105	121	120
(Cum. Credits (New Schedule)	556	1,128	1,306	1,304	1,315	1,371	1,457	1,562	1,683	1,803

Scenario 9 - Similar to Scenario 7; but with the use of E10 instead of E15; and with greater number of FFVs.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.50	1.50	1.38	1.37	1.36	1.30	1.15	0.93	0.65
Cane EtOH (bgal)	0	0	0	0.08	0.14	0.26	0.29	0.40	0.56	0.69
Cellulosic (bgal)	0	0	0	0.05	0.09	0.22	0.33	0.44	0.60	0.89
FFVs (1,000s)					400	1,270	1,600	2,000	2,400	3,030
Drop-in Fuel (bgal)	0	0	0	0	0.01	0.12	0.29	0.44	0.57	0.73
Total EtOH (bgal)	1.50	1.50	1.50	1.50	1.61	1.84	1.91	2.00	2.09	2.23
Total E85 (bgal)	0	0	0	0	0.15	0.47	0.58	0.71	0.84	1.03
Total CARBOB (bgal)	13.5	13.5	13.5	13.5	13.1	13.0	12.6	12.3	12.0	11.6
Avg.% EtOH	10.0	10.0	10.0	10.0	10.8	12.4	12.9	13.6	14.3	15.3
An. Credits (1,000s MT)	556	572	184	0	1	-1	1	1	0	2
Cum. Credits (1,000s MT)	556	1,128	1,312	1,312	1,313	1,312	1,313	1,314	1,314	1,316

Scenario 10 - Use of E10 instead of E15; same number of FFVs and about the same amount of drop-in as Scenario 8; but with greater amount of cellulosic ethanol than in Scenario 8; compliance achieved every year.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.50	1.50	1.56	1.63	1.57	1.47	1.37	1.20	1.00
Cane EtOH (bgal)	0	0	0	0.05	0.09	0.14	0.20	0.31	0.43	0.54
Cellulosic (bgal)	0	0	0	0.02	0.12	0.31	0.53	0.68	0.87	1.11
FFVs (1,000s)	0	0	0	400	1,200	1,900	2,600	3,300	3,900	4,600
FFVs % E85	50	50	50	50	50	50	50	50	50	50
Drop-in Fuel (bgal)	0	0	0	0	0.05	0.05	0.14	0.26	0.36	0.53
Total EtOH (bgal)	1.50	1.50	1.50	1.62	1.84	2.02	1.19	2.36	2.50	2.64
Total E85 (bgal)	0	0	0	0.15	0.45	0.70	0.94	1.17	1.36	1.57
Total CARBOB (bgal)	13.5	13.5	13.5	13.4	13.1	13.0	12.6	12.2	11.9	11.5
Avg.% EtOH	10.0	10.0	10.0	10.8	12.3	13.5	14.7	15.9	16.9	18.0
An. Credits (1,000s MT)	556	572	184	4	4	7	1	-1	2	2
Cum. Credits (1,000s MT)	556	1,128	1,312	1,316	1,320	1,327	1,328	1,327	1,329	1,331

Scenario 11 - Use of E10 instead of E15; fewer FFVs than Scenarios 9 and 10; about the same amount of cellulosic ethanol as Scenario 8; about the same amount of drop-in as Scenario 9; compliance achieved every year.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Corn EtOH (bgal)	1.50	1.50	1.50	1.38	1.29	1.14	1.06	0.92	0.62	0.44
Cane EtOH (bgal)	0	0	0	0.08	0.12	0.15	0.19	0.25	0.44	0.45
Cellulosic (bgal)	0	0	0	0.05	0.12	0.33	0.45	0.59	0.77	1.07
FFVs (1,000s)	0	0	0	0	150	500	800	1,100	1,400	2,000
FFVs % E85	50	50	50	50	50	50	50	50	50	50
Drop-in Fuel (bgal)	0	0	0	0	0.01	0.12	0.29	0.45	0.58	0.74
Total EtOH (bgal)	1.50	1.50	1.50	1.50	1.53	1.62	1.69	1.75	1.82	1.96
Total E85 (bgal)	0	0	0	0	0.06	0.18	0.29	0.39	0.49	0.68
Total CARBOB (bgal)	13.5	13.5	13.5	13.5	13.3	13.1	12.7	12.4	12.2	11.8
Avg.% EtOH	10.0	10.0	10.0	10.0	10.3	10.9	11.5	12.0	12.5	13.5
An. Credits (1,000s MT)	556	572	184	0	1	2	0	3	3	0
Cum. Credits (1,000s MT)	556	1,128	1,312	1,312	1,313	1,315	1,315	1,318	1,321	1,321

Summary of Diesel Scenarios

Assumptions Common to All Diesel Scenarios

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Soy BD CI (Scenarios 1-4)	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3
Soy BD CI (Scenario 5)		82.8	82.2	81.7	81.2	80.8	80.3	79.8	79.4	79.0
UCO BD CI	15.84	15.84	15.84	15.84	15.84	15.84	15.84	15.84	15.84	15.84
Canola BD CI (Scenario1 1-4)	62.99	62.99	62.99	62.99	62.99	62.99	62.99	62.99	62.99	62.99
Canola BD CI (Scenario 5)	62.99	62.17	61.36	60.58	59.81	59.07	58.34	59.81	56.94	56.27
Corn Oil BD CI	5	5	5	5	5	5	5	5	5	5
Tallow RD CI	29.49	29.49	29.49	29.49	29.49	29.49	29.49	29.49	29.49	29.49
Drop-In RD CI	35	35	35	35	35	35	35	35	35	35
CNG Use (million GDE)	115	121	129	136	143	148	157	164	172	177

Scenario 1 - Use of soy biodiesel and used cooking oil biodiesel

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Non-Conven. Diesel	0	0	4.5	8	10	15	20	20	20	20
Soy BD (mgal)	0	0	148	267	301	460	598	527	453	345
UCO BD (mgal)	0	0	0	3	43	68	121	208	299	425
Total BD (mgal)	0		148	270	344	528	719	735	752	770
Total Diesel (bgal)	3.2	3.2	3.3	3.4	3.4	3.5	3.6	3.7	3.8	3.9
An. Credits (1,000s MT)	110	17	1	3	-3	3	-1	0	0	1
Cum. Credits (1,000s MT)	110	127	128	131	128	131	130	130	130	131

Scenario 2 - Use of soy, used cooking oil, and canola biodiesel

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Non-Conv. Diesel	0	0	4.2	8	10	15	20	20	20	20
Soy BD (mgal)	0	0	138	267	298	449	574	491	398	258
UCO BD (mgal)	0	0	0	3	43	63	111	193	275	388
Canola BD (mgal)	0	0	0	0	3	16	35	52	79	123
Total BD (mgal)	0	0	138	270	344	528	720	736	752	769
Total Diesel (bgal)	3.2	3.2	3.3	3.4	3.4	3.5	3.6	3.7	3.8	3.9
An. Credits (1,000s MT)	110	17	6	3	3	-1	2	0	-2	2
Cum. Credits (1,000s MT)	110	127	133	136	139	138	140	140	138	140

Scenario 3 - Use of soy, used cooking oil, canola, and corn oil biodiesel

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Non-Conv. Diesel	0	0	4.2	8	10	15	20	20	20	20
Soy BD (mgal)	0	0	138	267	294	450	575	495	410	269
UCO BD (mgal)	0	0	0	3	40	57	93	167	248	354
Canola BD (mgal)	0	0	0	0	10	16	37	52	68	115
Corn Oil BD (mgal)	0	0	0	0	0	5	14	22	26	31
Total BD (mgal)	0	0	138	270	344	528	719	736	752	769
Total Diesel (bgal)	3.2	3.2	3.3	3.4	3.4	3.5	3.6	3.7	3.8	3.9
An. Credits (1,000s MT)	110	17	6	3	-3	2	-2	-1	-1	-2
Cum. Credits (1,000s MT)	110	127	133	136	133	135	133	132	131	129

Scenario 4 - Use of soy, used cooking oil, canola, and corn oil biodiesel, and tallow renewable diesel

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Non-Conv. Diesel	0	0	4	8	10	15	20	20	20	20
Soy BD (mgal)	0	0	132	267	296	450	573	491	403	265
UCO BD (mgal)	0	0	0	3	29	36	67	141	217	320
Canola BD (mgal)	0	0	0	0	7	16	36	52	71	115
Corn Oil BD (mgal)	0	0	0	0	6	13	22	26	30	35
Tallow RD (mgal)	0	0	0	0	6	13	22	26	30	35
Total BD and RD (mgal)	0	0	132	270	344	528	720	736	751	770
Total Conv. Diesel (bgal)	3.2	3.2	3.2	3.1	3.1	3.0	2.9	2.9	3.0	3.1
Total Diesel (bgal)	3.2	3.2	3.3	3.4	3.4	3.5	3.6	3.7	3.8	3.9
An. Credits (1,000s MT)	110	17	-4	3	1	-3	2	4	2	-1
Cum. Credits (1,000s MT)	110	127	123	126	127	124	126	130	132	131

Scenario 5 - Use of soy, used cooking oil, canola, and corn oil biodiesel, and tallow and drop-in renewable diesel

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Non-Conv. Diesel	0	0	3.8	7.4	10	15	20	20	20	20
Soy BD (mgal)	0	0	125	249	304	466	596	520	430	283
UCO BD (mgal)	0	0	0	0	18	23	30	99	169	262
Canola BD (mgal)	0	0	0	0	12	21	43	48	68	115
Corn Oil BD (mgal)	0	0	0	0	10	16	25	29	34	38
Drop-In RD (mgal)	0	0	0	0	0	2	26	39	51	71
Total BD and RD (mgal)	0	0	125	249	344	528	720	735	752	769
Total Conv. Diesel (bgal)	3.2	3.2	3.2	3.1	3.1	3.0	2.9	2.9	3.0	3.1
Total Diesel (bgal)	3.2	3.2	3.3	3.4	3.4	3.5	3.6	3.7	3.8	3.9
An. Credits (1,000s MT)	110	17	3	-1	0	2	1	1	-2	3
Cum. Credits (1,000s MT)	110	127	130	129	129	131	132	133	131	134

Table 1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Evaporative Loss Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Methanol / Sodium Methoxide receiving and storage			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Fermentation process: yeast, liquefaction, beerwell, and process condensate tanks			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Distillation and wet cake processes			Emission limit corresponding to use of a VOC control system (wet scrubber or equivalent) capable of 95% or better control efficiency		
Pumps and compressor seals			No leak of methane greater than 100 ppm above background and inspection and maintenance program		
Valves, flanges, and other types of connectors			No leak of methane greater than 100 ppm above		

Table 1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Evaporative Loss Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
			background and inspection and maintenance program		
Storage tank (fixed roof)			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Storage tank (floating roof)			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Liquid fuel loading operations			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Liquid fuel transfer and dispensing operations			Emission limit corresponding to use of an ARB certified Phase I vapor recovery system		

Table 2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Natural gas-fired boiler, ≥2 to <5 MMBtu/hr	Non-atmospheric units: 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu) Atmospheric units: 12 ppmvd @ 3% O_2 (0.015 lb/MMBtu)	Firetube type: 50 ppmvd @ 3% O_2 Watertube type: 100 ppmvd @ 3% O_2	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired boiler, ≥5 to <20 MMBtu/hr	6 ppmvd @ 3% O_2 (0.007 lb/MMBtu)	Firetube type: ≤50 ppmvd @ 3% O_2 Watertube type: ≤100 ppmvd @ 3% O_2	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired boiler, ≥20 MMBtu/hr	5 ppmvd @ 3% O_2 (0.0062 lb/MMBtu)	Firetube type: ≤50 ppmvd @ 3% O_2 Watertube type: ≤100 ppmvd @ 3% O_2 For units ≥250 MMBtu/hr[123]: 10 ppmvd @ 3% O_2	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired dryer	0.018 lb/MMBtu (15 ppmv @ 3% O_2)	0.07 lb/MMBtu	Emission limit corresponding to use of a VOC capture and control with thermal or catalytic incineration (98% control)	Emission limit corresponding to use of a wet scrubber (95% control)	Emission limit corresponding to use of high efficiency (1D-3D) cyclones and thermal incinerator in series

[123] This CO limit may be required for boilers rated at <250 MMBtu/hr if an oxidation catalyst is found to be cost effective, is necessary to meet toxic best available control technology, or for VOC emission control.

Table 2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
			or equivalent		(98.5% control) or equivalent
Flare (ethanol production)	0.05 lb/MMBtu	0.37 lb/MMBtu	0.063 lb/MMBtu	0.00285 lb/MMBtu	0.008 lb/MMBtu
Biomass-fired boiler	0.012 lb/MMBtu (*9 ppmvd @ 3% O_2*)	0.046 lb/MMBtu (*59 ppmvd @ 3% O_2*) Alternate Limit: 0.01 lb/MMBtu (*22 ppmvd @ 3% O_2*)	0.005 lb/MMBtu (*11 ppmvd @ 3% O_2*)	0.012 lb/MMBtu (*7 ppmvd @ 3% O_2*)	0.024 lb/MMBtu (*0.01 gr/scf @ 12% CO_2*)
Landfill gas-fired flare	0.025 lb/MMBtu	0.06 lb/MMBtu	Emission limit corresponding to 98% VOC destruction efficiency or 20 ppmv @ 3% O_2	Emission limit corresponding to use of a wet scrubber with 98% control efficiency	Emission limit corresponding to use of steam injection and/or knockout vessel
Manure digester and co-digester gas-fired flare	0.03 lb/MMBtu (*25 ppmvd @ 3% O_2*)	Operate per manufacturer specifications to minimize CO	0.03 lb/MMBtu	Emission limit corresponding to use of a H_2S removal system (dry or wet scrubber or equivalent)	Emission limit corresponding to use of smokeless combustion and LPG or natural gas-fired pilot
Biogas-fired microturbine	0.5 lb/MWh As of 1/1/2013: 0.07 lb/MWh	6.0 lb/MWh As of 1/1/2013: 0.10 lb/MWh	1.0 lb/MWh As of 1/1/2013: 0.02 lb/MWh	N/A	N/A
Biogas-fired reciprocating internal combustion engine	11 ppmvd @ 15% O_2 (or 0.15 g/bhp-hr) in conjunction with an effective and efficient biogas treatment system Alternate Limit for dairy	250 ppmvd @ 15% O_2	20 ppmvd @ 15% O_2	Emission limit corresponding to use of a fuel gas pretreatment system for sulfur removal along with maximum fuel sulfur content limit	0.1 g/bhp-hr

Table 2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
	digester gas-fired rich-burn engines: 9 ppmvd @ 15% O_2 (or 0.15 g/bhp-hr)				
Biogas-fired turbine, <3 MW	9 ppmvd @ 15% O_2	60 ppmvd @ 15% O_2	3.5 ppmvd @ 15% O_2[124]	Landfill gas: Emission limit corresponding to use of landfill gas with sulfur content of no more than 150 ppmv as H_2S Digester gas: Emission limit corresponding to use of digester gas with sulfur content of no more than 40 ppmv as H_2S	Emission limit corresponding to use of a fuel gas pretreatment system for particulate removal
Biogas-fired turbine, ≥3 MW	5 ppmvd @ 15% O_2				
Biomass syngas-fueled[125] reciprocating internal combustion engine	5 ppmvd @ 15% O_2	N/A	25 ppmvd @ 15% O_2	N/A	N/A
Diesel-fueled emergency engine generator	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for Stationary Compression	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for	Emission limit corresponding to use of CARB, or very low sulfur, diesel fuel (15 ppm sulfur by	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for

[124] Due to limited data set available for this Report on achievable VOC emission levels for landfill and digester gas-fired turbines, ARB staff recommends that regulatory agencies consult with the manufacturers on guaranteed emission levels, as well as, evaluate additional source tests to determine the appropriate VOC limit for a turbine.
[125] BACT guideline that is the basis of these emission limits defines syngas, or synthetic gas, to be "derived from biomass (agricultural waste) by gasification or similar processes. Syngas is distinguished from waste gases by its low methane content (<5%) and comparatively high hydrogen gas content (15% or greater), although frequently over half of the syngas composition is non-combustible gases such as nitrogen and carbon dioxide."

Table 2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
	Ignition Engines for applicable horsepower range[126]	Stationary Compression Ignition Engines for applicable horsepower range	Stationary Compression Ignition Engines for applicable horsepower range	weight)	Stationary Compression Ignition Engines for applicable horsepower range

Table 3. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Miscellaneous Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Grain receiving, conveying, and grinding operations					Emission limit corresponding to use of a baghouse with 99% control, or equivalent
Wet cooling tower					Emission limit corresponding to use of a drift eliminator with 0.0005% drift loss
Compressed gas dispensing operations	No emissions – use of closed loop system with all vent and excess process gas directed to an onsite treatment system, used in vehicles, or directed to another combustion or processing facility that can process the biogas and which has been issued a valid air permit				

126 Refer to ARB regulations and/or Appendix D Table D-29 of the guidance for the applicable emission standard.

Table 3. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Miscellaneous Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Biogas-fueled fuel cell[127]	0.5 lb/MWh Alternate Limit: 0.07 lb/MWh	6.0 lb/MWh Alternate Limit: 0.10 lb/MWh	1.0 lb/MWh Alternate Limit: 0.02 lb/MWh	N/A	N/A
Composting			Emission limit corresponding to use of a VOC control system (enclosure with biofilter or equivalent) capable of 80% or better control efficiency Ammonia: Emission limit corresponding to use of an NH3 control system capable of 80% or better control efficiency		Emission limit corresponding to use of a PM10 control system capable of 99% or better control efficiency

[127] Emission limits are the 2008 standards for waste gas required by the ARB's Distribution Generation (DG) Certification Regulation. Alternate limits represent the 2013 standards for waste gas required by the DG Certification Regulation.