APPENDIX B

DEVELOPMENT OF ILLUSTRATIVE COMPLIANCE SCENARIOS AND EVALUATION OF POTENTIAL COMPLIANCE CURVES

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Development of Illustrative Compliance Scenarios and Evaluation of Potential Compliance Curves

A step-by-step approach was used to determine the feasibility of complying with an LCFS CI reduction goal of ten percent by 2020. The steps included the following for the ten-year period between 2016 and 2025:

- An assessment of the amount of low CI fuels potentially available to California;
- A projection of the expected California demand for transportation fuel energy;
- A assessment of the banked credits that the current LCFS is likely to carry over into 2016;
- An evaluation of the likely CIs of the fuels that could be used to create LCFS credits;
- An estimate of the impact of other credit producing options (such as refinery improvements) proposed in the re-adopted LCFS;
- Recalibration of the LCFS standard to reflect revised estimates of the CIs of the fuels used in 2010 to establish an LCFS baseline;
- Consideration of factors that will influence the choice of fuels available for use under the LCFS; and
- Use of a spreadsheet analysis to determine a feasible fuel mix of lower CI fuels that:
    - meets the demand for transportation energy,
    - produces sufficient credits to comply with a ten percent reduction goal, and
    - provides sufficient credit generation to sustain compliance beyond 2020.

The following discussion describes how ARB staff developed this analysis.

A. Assessment of Fuel Availability

The re-adoption of the LCFS allowed ARB staff to reevaluate fuel availability for compliance with the LCFS standards. In order to determine what fuels would come to California, staff needed to consider what fuels would be available nationally. National fuel availability would set an upper bound on the maximum volumes of fuels that could be used to comply with the LCFS. From the national fuel availability supply, the LCFS would attract the lowest-CI fuels to California.

1. Low Carbon Fuel Overview

The following section briefly describes the low carbon fuels that staff analyzed in the fuel availability study.

a. Ethanol from Grains and Sugars

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

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

b. Ethanol from Grains

Currently, corn is the primary feedstock for ethanol production in the United States. Studies indicate that approximately 98 percent of current ethanol production in the United States uses corn, with about 80 percent of the ethanol produced from a dry-mill process.

i. Dry Mill

In the dry mill process, the grain feedstock is milled into a flour or fine meal to expose the starch. Starch is a polymer of glucose and must be broken down before fermentation. The flour is mixed with water and then cooked at high temperatures with enzymes to convert the starch to sugar and reduce bacterial contamination. After the starch has been hydrolyzed to its component sugars (glucose), the glucose is fermented using yeast under anaerobic conditions. The hydrolysis and fermentation process usually takes 40 to 50 hours. After fermentation, the ethanol is concentrated to

95 percent using conventional distillation and then dehydrated (e.g., by using molecular sieves, azeotropic distillation, or extractive distillation). The ethanol is denatured, usually by the addition of gasoline to prevent consumption as an alcoholic beverage.

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

ii. Wet Mill

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

c. Ethanol from Sugar Crops

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

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

Sugar-to-ethanol conversion technology is fully commercial (mostly in Brazil). Sugarcane ethanol production is efficient and results in a lower-carbon-intensity ethanol. However, indirect land use effects impact the carbon intensity.
Ethanol produced from sugar crops grown in the United States is also an option, though availability is limited. Ethanol is generally produced from sugars where there is a large supply of feedstock, such as sugarcane in Brazil and sugar beets in parts of Europe.

Feedstocks in North America are limited but could be increased. California and other states produce sugar crops for the sugar industry.

d. Biodiesel and Renewable Diesel

i. Biodiesel

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

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

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

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

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

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

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

According to Biodiesel Magazine[1], as of September 2013 there were 204 operational commercial biodiesel production plants in the U.S. with a total production capacity of 2.9 billion gallons. There are about 12 major plants in California with annual production capacities varying between one million gallons to 36 million gallons. The total capacity in California is about 100 million gallons per year.

ii. Renewable Diesel

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

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

Renewable diesel has several advantages to FAME and petroleum biodiesel. Renewable diesel generally has a superior emission profile. The use of renewable diesel results in reduced particulate, NO_X, hydrocarbons, and CO emissions. Unlike FAME biodiesel, the production of renewable diesel through the FAHC process does not produce a glycerin co-product. Renewable diesel may be produced using existing hydrotreatment process equipment in a petroleum refinery, which would result in lower capital investments; however, renewable diesel requires higher operating costs than biodiesel.

[1] http://www.biodieselmagazine.com/

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

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

iii. Biogas

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

Landfill Gas (LFG)

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

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

Vehicle Fuel from Landfill Gas

The main steps involved in processing landfill gas into CNG are water removal, pretreatment to remove trace organics, membrane technology to separate CO_2, and final compression to about 3600 psi. Production of LNG from landfill gas is more challenging and requires additional steps in the form of purification and cryogenic systems.

Digester Gas

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

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

Digester Gas Applications

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

e. Natural Gas (CNG, LNG)

The production of natural gas, in both compressed (CNG) and liquefied (LNG) forms, involves mature technologies and is clearly technologically feasible vis-à-vis the LCFS regulation. Britain was the first country to commercialize the use of natural gas. Around 1785, natural gas produced from coal was used to light houses, as well as streetlights.

In 1821, William Hart dug the first well in the U.S. (in Fredonia, New York) specifically intended to obtain natural gas. Natural gas liquefaction dates back to the 19th century, and the first commercial liquefaction plant began operation in West Virginia in 1917. Today, the natural gas industry has existed in this country for over 100 years and continues to grow.

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

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

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

- Oil and Condensate Removal,
- Water Removal,
- Separation of Natural Gas Liquids, and
- Sulfur and Carbon Dioxide Removal.

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

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

f. Electricity

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

Battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) are examples of two technologies that use electricity as a transportation fuel. The status of zero-emission vehicle technologies was reviewed in the "Joint Technical Assessment Report" developed in 2010 by the U.S. EPA, National Highway Traffic Safety Administration, and ARB. The report concluded "electric drive vehicles including hybrid(s)…battery electric vehicles…plug-in hybrid(s)…and hydrogen fuel cell vehicles…can dramatically reduce petroleum consumption and GHG emissions compared to conventional technologies...The future rate of penetration of these technologies into the vehicle fleet is not only related to future GHG and CAFE standards, but also to future reductions in HEV/PHEV/EV [electric vehicle] battery costs, the overall performance and consumer demand for the advanced technologies…." Manufacturers confirmed in meetings leading up to the release of the report, their commitment to develop ZEV technologies. "…[A] number of the firms suggested that in the 2020 timeframe their U.S. sales of HEVs, PHEVs, and EVs [electric vehicle] combined could be on the order of 15-20% of their production." (EPA, 2010, pp.2-5) In September 2014, California BEV and PHEV sales passed the 100,000 mark,[2] with roughly equal numbers of BEVs and PHEVs, demonstrating that the initial California market has accepted both technologies in equal numbers.

In February 2013, Governor Brown's Interagency Working Group on Zero Emission Vehicles released the "ZEV action Plan: A road map toward 1.5 million ZEVs on California roadways by 2025.[3]" The state is poised to complete the first set of milestones which establish the framework for ZEV infrastructure planning and investment by 2015. California is well on its way towards achieving the next major milestone of having sufficient infrastructure to support one million ZEVs by 2020.

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

[2] http://www.pevcollaborative.org/sites/all/themes/pev/files/docs/140908_News%20Release_Final.pdf
[3] http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf

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

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

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

In May 2014, the National Renewable Energy Laboratory (NREL) completed a "California Statewide Plug-in Electric Vehicle Infrastructure Assessment[4]" to estimate BEV and PHEV infrastructure needed to accommodate one million ZEVs in 2020. Assuming ZEV adoption follows the ZEV compliance projections from ARB's Advance Clean Car rulemaking, achieving one million electric vehicles on California roadways is estimated to occur in the 2023-2024 timeframe. The NREL report estimates that in this timeframe, these plug-in electric vehicles would consume roughly 2.8 TW-hours per year. Based on these assumptions, the associated annual electrical demand in 2020 would be slightly less than 2.8 TW-hours per year.

Since most of this additional demand would be supplied by off-peak power, electric vehicles would not create an adverse impact on California's supply of available electric power within the 2020 timeframe. A potential benefit of plug-in or electric vehicles for the "smart" power grid of the future involves the concept of managed charging, where electric vehicles are signaled to charge when energy is in surplus (i.e., during times of peak wind or solar generation), and then using the stored energy in electric vehicles to supply power to the grid during peak demand periods. This "vehicle-grid integration" (VGI) concept would involve advanced technology that would allow managed charging and discharging of future plugged-in vehicles to transmit their location and storage capacity to the electric power grid. The 2014 "California Vehicle Grid Integration Roadmap"[5] establishes a framework for identifying the barriers to and understanding

[4] http://www.energy.ca.gov/2014publications/CEC-600-2014-003/CEC-600-2014-003.pdf
[5] http://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf

the value proposition of VGI to vehicle owners, charging station owner/operators, utilities, grid operators and wholesale energy providers. With vehicle-to-grid (V2G), utilities could potentially draw small amounts of power from the vehicle's battery packs to provide voltage regulation, spinning reserves, and other power balancing functions. Several pilot studies involving car companies, utilities, grid operators, and academia are currently underway to better understand how to overcome various technical challenges associated with VGI.

g. Hydrogen

Most hydrogen used for fuel cell electric vehicles is produced from large scale steam methane reformers (SMR) that typically support petroleum refining, semiconductor and fertilizer manufacture and food processing operations. Senate Bill 1505, (Chapter 877, 2006) sets environmental standards on the production of hydrogen for California's Fuel Cell Electric Vehicle fleet including at least 30 percent greenhouse gas emission reductions compare to gasoline and the utilization of at least 33.3 percent renewable energy resources for feedstock and/or process energy. In the near term transportation hydrogen will be produced through renewable pathways including electrolysis of water using photovoltaic power, and the reformation and cleanup of bio/digester gas at solid waste and water treatment plants. Additionally, at least one marketer of hydrogen gas is able to obtain the fuel as a by-product of a separate industrial process. Carbon capture and sequestration are also being investigated to reduce the carbon intensity of SMR produced hydrogen. The currently operational and funded hydrogen network will reach 46 percent utilization of renewable resources after all currently planned stations are built. A well-to-wheels analysis for the 28 most recently funded stations indicates GHG emission benefits of 77 percent[6].

When hydrogen is produced at central facilities and distributed to fueling stations, it is typically delivered via trucks carrying tubes full of compressed hydrogen gas. Hydrogen can also be transported and delivered in its liquid state. California is also host to a fueling station that receives its hydrogen via pipeline from a SMR facility that is delivering to a nearby petroleum refinery. Hydrogen is dispensed as a gas into vehicles following procedures accepted industry to provide a final on-vehicle pressure of 35MPa to 70MPa depending on the vehicle tank's design. 70MPa is currently more common in light duty vehicle designs and 35MPa is more common in medium and heavy duty designs. Typical 70MPa psi tanks for light duty vehicles carry from five to seven kg of hydrogen. Transit buses carry as much as 40 kg of hydrogen. The process is similar for hydrogen that arrives as a liquid, with the addition of a vaporization step to convert the liquid to a gas prior to dispensing.

Hydrogen produced on-site, via SMR or electrolysis, is typically stored in gaseous form. Storage, compression, and dispensing steps are then essentially identical to stations that receive hydrogen deliveries from a central source.

[6] "Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development", June 2014, California Air Resources Board

For its first Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development, published in June 2014[7], ARB projected 23 hydrogen fueling stations would be publically available in California by the end of 2014. By the end of 2015, that number is currently projected to increase to 51. Based on collaboration with the California Energy Commission (CEC), ARB also reported the possibility for up to 100 stations by the end of 2020. The locations of the first 51 stations have been chosen to closely align with the California Fuel Cell Partnership's Road Map[8] document. The strategy adopted within the roadmap specifies five main clusters for station deployment (Berkeley, Coastal/South Orange County, Torrance, West Los Angeles/Santa Monica, and South San Francisco/Bay Area) along with key connector and vacation destination stations. This methodology is intended to maximize the coverage of areas that can provide reliable fueling service to early adopters of fuel cell electric vehicles (FCEVs). Based on the planned infrastructure by 2015, it is expected that FCEV drivers will be able to drive between northern and southern California and visit destinations in Lake Tahoe, Santa Barbara, and San Diego.

Even though small fleets of FCEV's have been on the road for years, as of 2014, FCEVs are now commercially available. In June 2014, Hyundai started to lease a standard production line FCEV, the Tucson Fuel Cell compact sport utility vehicle. Toyota has announced the commercial launch of its Mirai sedan for late 2015. Honda has announced a market launch for its upcoming vehicle in 2016. In addition, a number of partnerships have developed among manufacturers to collaborate on fuel cell technology development and cost reduction. Indications from industry demonstrate that significant progress has been made to address previous technical barriers to commercialization; the focus of development is now on reducing costs, which will be aided by production at scale. Governor Brown's Executive Order B-16-2012 directs the ARB and CEC to take action to help ensure the deployment of 1.5 million ZEVs throughout the state by 2025, including FCEVs. This order, combined with ARB's ZEV mandate, the infrastructure incentives secured by AB 8, and many other State actions will establish a supportive environment for the launch of the commercial FCEV market.

2. LCFS Low CI Fuel Projections Methodology

Initially, staff researched published national low-CI fuel projections through 2020. There were several studies that projected alternative fuels through 2020 and beyond in an aggregated level. For example, the reports would project total biodiesel volumes, but it would not project them by feedstock type. Different feedstocks have significantly different CI values, and the LCFS was designed to attract the lowest CI fuels to California. In order to determine what fuels would be available to comply with the LCFS, staff determined that it would need a more disaggregated low-CI fuel projection. Having found that none of the published fuel projection reports were disaggregated by

[7] "Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development", June 2014, California Air Resources Board
[8] "A California Road Map: The Commercialization of Hydrogen Fuel Cell Vehicles", June 2012, California Fuel Cell Partnership

feedstock, staff determined that it would have to design its own low-CI fuel projection analysis.

a. General Methodology

The first step for the fuel availability study was to look at statewide, national, and/or worldwide capacity of each low-CI fuel. Staff then looked into information that pertained to the past and current production of each low-CI fuel. From that information, staff could get a sense of an overall trend for each of the fuels. Digging further, staff then investigated the past and current production of each low-CI fuel by feedstock and looked for growth patterns for each feedstock. Some feedstocks, such as used cooking oil and tallow, are currently growing at relatively rapid rates compared to others, but these feedstocks are limited. Staff investigated potential feedstock growth limitations and applied the growth limitations to the fuel projections.

b. Specific Low-CI Fuel Projection Methodology

The following section describes the fuel projection methodology applied to each low-CI fuel.

i. Corn Ethanol

Ethanol is the dominant oxygenate for reformulated gasoline. The majority of California Reformulated Gasoline sold is blended with ethanol at ten percent by volume (E10). As E10 is the only ethanol blend that is approved for use in all in-use light duty vehicles, the penetration of ethanol above ten percent is limited by physical constraints, such as the penetration rate of flex-fuel vehicles, which are compatible with higher blends of ethanol, and the availability of refueling stations offering higher blends of ethanol. These physical limits to the penetration of ethanol in blends greater than ten percent are often referred to as the “E10 blendwall.”

While the E10 blendwall limits the volume of ethanol that California’s transportation fleet can consume in levels above ten percent, higher blends of ethanol are also available. The U.S. EPA allows blends of 15 percent by volume (E15) in 2001 and newer cars, although E15 sales in California are not currently allowed. Flex-fuel vehicles can also use ethanol blends up to 85 percent by volume (E85). Historical data submitted to ARB from regulated parties via the LCFS Reporting Tool (LRT) shows that California drivers consumed approximately 221 million gallons of ethanol as E85 in 2013. As California has reached the E10 blendwall, E85 provides opportunities for growth in the demand for ethanol. The amount of E85 that is anticipated to be consumed in California will depend on physical constraints, such as the availability of refueling stations offering E85 and the penetration rate of flex-fuel vehicles, as well as consumer demand for higher-ethanol blends, which is predominately determined by the price of ethanol relative to gasoline. On a volumetric basis, ethanol has approximately 67 percent of the energy density of gasoline, meaning that the price of a gallon of ethanol must be approximately

67 percent of the price of a gallon of gasoline – or 33 percent cheaper – in order for consumers to be able to drive the same distance for the same price.

The U.S. Energy Information Agency's (EIA) *2014 Annual Energy Outlook* forecast of the national average prices for ethanol and gasoline indicates that ethanol will not be cost-competitive with gasoline on an energy-equivalent basis. This is anticipated to slow the growth in consumer demand for higher-ethanol blends, such as E85. For this reason, staff forecasts that California's demand for E85 will grow at a modest rate through 2020. Staff anticipates that the demand for E85 will continue to grow modestly, even in a scenario where ethanol is not cost competitive with gasoline on an energy-equivalent basis, because economic considerations are not the sole determinant of demand for E85; consumers also choose to refuel with higher ethanol blends for environmental benefits. Historical data submitted to ARB from regulated parties via the LCFS Reporting Tool (LRT) supports these projections: demand for, and consumption of, E85 has increased from the inception of the LCFS in 2010 even without ethanol reaching price parity with gasoline on an energy-equivalent basis. Staff anticipates a continuation of this trend through 2020. This increased penetration of E85 is facilitated by the increased availability of E85 refueling stations and the increased penetration of flex-fuel vehicles as they comprise a greater proportion of in-use light duty vehicles over time.

ii. Ethanol from Grains

Ethanol from grains is produced in quantities that greatly exceed California's demand. The federal RFS2 incentivizes the production of grain ethanol, and the domestic production capacity is greater than the anticipated demand for a national average of E10. As grain ethanols tend to be characterized by higher CI values than other ethanol types, these fuels are anticipated to comprise a decreasing proportion of the ethanol consumed in California in later years when the stringency of the program increases.

By 2020, staff anticipates that the production of grain ethanol will result in a national supply of approximately 14.8 billion gallons of grain ethanol. California is anticipated to attract a small portion of this supply, as the volume of ethanol that is anticipated to be consumed is limited by the E10 blendwall, and because of the relative attractiveness of other sources of ethanol with lower carbon intensity values. Nonetheless, the relatively low cost of producing grain ethanol, and its abundant availability, enables grain ethanol to continue to play an important role as a low-CI fuel in future years. Staff analysis projects that grain ethanol will generate a large portion of LCFS credits through 2020.

iii. Ethanol from Sugar

Brazilian sugarcane ethanol production forecasts are from Food and Agricultural Policy Research Institute (FAPRI) World Agricultural Outlook. Staff accounted for domestic consumption, and then looked at excess ethanol production above domestic consumption as volumes available for export. Staff assumed that 60 percent of the excess volumes are assumed to be available for California consumption. This

60 percent assumption is considered conservative since 60 percent is lees that the amount that has been exported to the U.S. previously.

iv. Cellulosic Ethanol

Cellulosic ethanol production from U.S. producers for 2013 to 2015 volumes is based EIA's forecasted domestic capacity from plants either being built or that are already built. To remain conservative, ARB discounted EIA's 2014 and 2015 production forecast by approximately half. To account for potential challenges in the early production phases of cellulosic ethanol, the penetration of cellulosic ethanol into the market is limited before 2016 to several planned projects with aggregate nameplate capacity of approximately 250 million gallons per year. This is an assumption in the LCFS supply analysis, borrowed from the U.S. EIA. Cellulosic ethanol supply from U.S. producers after 2016 is limited to the EIA's low-cost renewable technology scenario.

Brazilian cellulosic ethanol projections are based on publicly available announcements from the suppliers, and staff discussion with two Brazilian cellulosic ethanol producers. Two Brazilian companies have begun producing or are building facilities anticipated to produce cellulosic ethanol in 2014. They both are using bolt-on technology that has been commercially proven and have announced plans to build additional facilities. To remain conservative, ARB staff discounted the planned growth in productive capacity by 25 percent.

Brazilian cellulosic is further along in development than its domestic counterpart, and so it is assumed to scale more quickly (assisted by the economic attractiveness of bolt-on cellulosic facilities co-located with existing, first-generation cane ethanol producers). Scaling for Brazilian cellulosic is loosely modeled on the historic growth in productive capacity for renewable diesel.

The Tables B-1, B-2, and B-3 below show Staff's projections for Ethanol availability through 2020.

B-1. Max. Volumes of Low-CI Fuels: Reference Case

Fuel Category	Volume Units	2014 Volume	2015 Volume	2016 Volume	2017 Volume	2018 Volume	2019 Volume	2020 Volume
Corn Ethanol	mil gal	11,658	11,845	12,041	12,264	12,428	12,677	12,616
Sorghum Ethanol	mil gal	2,057	2,090	2,125	2,164	2,193	2,237	2,226
Cane Ethanol	mil gal	608	553	657	881	1,144	1,374	1,479
Molasses Ethanol	mil gal	118	226	249	276	304	331	355
Cellulosic Ethanol (domestic)	mil gal	23	92	141	187	216	247	284
Cellulosic Ethanol (total)	mil gal	52	163	272	372	435	476	512

B-2. Max. Volumes of Low-CI Fuels: High Case

Fuel Category	Volume Units	2014 Volume	2015 Volume	2016 Volume	2017 Volume	2018 Volume	2019 Volume	2020 Volume
Corn Ethanol	mil gal	11,658	11,845	12,041	12,264	12,428	12,677	12,616
Sorghum Ethanol	mil gal	2,057	2,090	2,125	2,164	2,193	2,237	2,226
Cane Ethanol	mil gal	735	612	733	1,012	1,338	1,631	1,756
Molasses Ethanol	mil gal	177	340	374	414	456	496	532
Cellulosic Ethanol (domestic)	mil gal	128	250	306	367	440	528	634
Cellulosic Ethanol (total)	mil gal	160	361	496	617	730	818	924

B-3. Max. Volumes of Low-CI Fuels: Low Case

Fuel Category	Volume Units	2014 Volume	2015 Volume	2016 Volume	2017 Volume	2018 Volume	2019 Volume	2020 Volume
Corn Ethanol	mil gal	11,658	11,845	12,041	12,264	12,428	12,677	12,616
Sorghum Ethanol	mil gal	2,057	2,090	2,125	2,164	2,193	2,237	2,226
Cane Ethanol	mil gal	351	347	404	520	665	786	849
Molasses Ethanol	mil gal	59	113	125	138	152	165	177
Cellulosic Ethanol (domestic)	mil gal	64	125	127	127	127	127	127
Cellulosic Ethanol (total)	mil gal	90	157	245	275	295	295	295

v. Biodiesel

The U.S. EIA has detailed information about U.S. biodiesel production capacity, historical production, and feedstocks[9]. Staff first looked at the current total production capacity of biodiesel in the United States. The total production capacity at the end of 2013 was 2.31 billion gallons. The total biodiesel production for 2013 was 1.36 billion gallons. The biodiesel production capacity is currently overbuilt for current demand. The amount of biodiesel production capacity is not a limiting factor in the growth of the biodiesel industry.

Next, staff looked at potential feedstock constraints and investigated the major feedstocks for the production of biodiesel. The major feedstocks of biodiesel are canola, soy, waste grease, corn oil, tallow, and palm oil. EIA has historic data on the amounts of feedstocks that were used to make biodiesel[10]. Staff used the historic data to extrapolate growth potential for the use of each feedstock in biodiesel production. However, staff noticed that tallow and used cooking oil were being used in increasing quantities in the last few years and that the continued high growth of these feedstocks was unsustainable. Therefore, staff decided to investigate each of the feedstocks and

[9] http://www.eia.gov/biofuels/biodiesel/production/
[10] http://www.eia.gov/biofuels/biodiesel/production/table3.pdf

their growth potential for use as a biodiesel feedstock. Staff did extensive research from industry, government, and academic resources about each of the feedstocks and determined that it would have to mitigate the growth from the tallow and used cooking oil sectors and set a cap on the amount that could be used as a biodiesel feedstock. The general consensus was that the industry was using most of the economical tallow and waste grease and that growth from those feedstocks would soon slowdown.

The renewable fuels standard (RFS) is the main driving force behind biodiesel demand. The RFS sets the amount of Renewable Identification Numbers (RINs) that biodiesel may generate. The RINs provide a credit for every gallon of biodiesel that generates a RIN. Biodiesel production has been closely following the amount of RINs allowed to be generated by the RFS. There has been a lot of uncertainty surrounding the RFS and the amount of RINs allowed to be generated by each fuel. Staff understands biodiesel growth is tied closely to the RFS, but cannot predict where the RFS is headed. Staff made biodiesel projections based on feedstock growth and overall historical growth. See Tables B-4, B-5, and B-6 below for biodiesel production projections.

B-4. Biodiesel Low Case Projection

Fuel	Units	2013	2014	2015	2016	2017	2018	2019	2020
Canola Biodiesel	MM gal.	87	85	80	75	80	85	90	95
Soy Biodiesel	MM gal.	744	750	775	800	825	850	875	900
Waste Grease / UCO Biodiesel	MM gal.	157	157	160	165	170	175	180	185
Corn Oil Biodiesel	MM gal.	136	150	175	225	250	300	350	400
Tallow Biodiesel	MM gal.	147	150	155	160	165	170	175	180
Palm Oil Biodiesel	MM gal.	85	85	90	92	95	100	110	115
Total Biodiesel	**MM gal.**	**1356**	**1,377**	**1,435**	**1,517**	**1,585**	**1,680**	**1,780**	**1,875**

B-5. Biodiesel Medium Case Projection

Fuel	Units	2013	2014	2015	2016	2017	2018	2019	2020
Canola Biodiesel	MM gal.	87	87	90	92	95	98	100	105
Soy Biodiesel	MM gal.	744	775	825	875	900	950	1,000	1,050
Waste Grease / UCO Biodiesel	MM gal.	157	160	165	170	175	180	190	200
Corn Oil Biodiesel	MM gal.	136	175	225	250	300	350	400	450
Tallow Biodiesel	MM gal.	147	165	175	180	185	195	200	210
Palm Oil Biodiesel	MM gal.	85	90	95	100	105	110	115	120
Total Biodiesel	**MM gal.**	**1356**	**1,452**	**1,575**	**1,667**	**1,760**	**1,883**	**2,005**	**2,135**

B-6. Biodiesel High Case Projection

Fuel	Units	2013	2014	2015	2016	2017	2018	2019	2020
Canola Biodiesel	MM gal.	87	95	96	99	102	105	110	125
Soy Biodiesel	MM gal.	744	820	860	902	950	995	1,050	1,100
Waste Grease / UCO Biodiesel	MM gal.	157	175	180	185	190	195	200	210
Corn Oil Biodiesel	MM gal.	136	200	250	300	350	400	450	500
Tallow Biodiesel	MM gal.	147	175	180	190	200	210	225	250
Palm Oil Biodiesel	MM gal.	85	95	100	105	110	115	125	150
Total Biodiesel	**MM gal.**	**1356**	**1,560**	**1,666**	**1,781**	**1,902**	**2,019**	**2,160**	**2,335**

vi. Renewable Diesel

Renewable diesel (RD) is a large credit producer under the LCFS, and it is expected to continue to contribute increasingly to the LCFS and California's clean fuels program in general. As such, it is imperative for ARB staff to understand the extent of availability of RD in the U.S. and accordingly be able to project reasonable amounts of RD that could be expected to be drawn to the California market. Given this objective, staff seeks to characterize the currently available volumes of RD, and use those and currently planned projects as a basis for projecting the available supply of RD in the U.S. in 2020.

Current RD Production Capacity

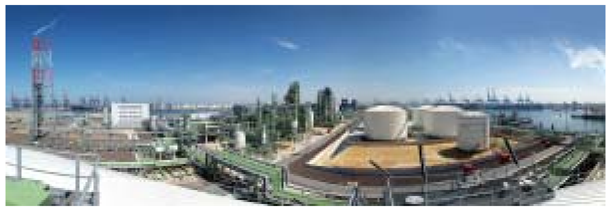
Staff is aware of five currently operating commercial scale RD plants whose fuels are or may potentially become available to the U.S. market. The companies and RD production plants currently existing are listed below, along with their production capacities.

Diamond Green
Norco, Louisiana
137 million gallons per year (MGPY)[11]

REG Synthetic Fuels
Geismar, Louisiana
75 MGPY[12]

Neste Oil Company
Singapore
240 MGPY[13] (550 million EUR, approx. $733 million in 2010)

Rotterdam, Netherlands
240 MGPY[14]



Porvoo, Finland
158 MGPY[15]

Total Current U.S. Production Capacity: 212 MGPY

Total Current World Production Capacity: 850 MGPY

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11 http://www.darpro.com/diamond-green-diesel
12 http://regi.com/node/686
13 http://www.nesteoil.com/default.asp?path=1,41,537,2397,14090
14 http://www.nesteoil.com/default.asp?path=1,41,537,2397,14089; 800,00 t/a is about 240 MGPY according to http://www.biofuelsdigest.com/bdigest/2010/12/03/neste-oil-becomes-chief-monster-as-renewable-diesel-becomes-biofuels-monster/
15 http://nesteoil.com/default.asp?path=1,41,537,2397,2235; 525,000 t/a is about 158 MGPY

Feedstock Constraints

Most of the RD currently supplied to the U.S. is derived from tallow feedstocks. In 2014, the U.S. supply is on track to reach 400 million gallons of RD (200 million gallons as of July 2014 according to EPA[16]). Additional availability of tallow feedstocks are not certain, as most of the U.S. supply of tallow may not be available to RD production, and international tallow is already being drawn to the U.S. in large amounts. However, RD can be produced from any fatty acid feedstock.

In the U.S., there are currently two major feedstocks that could be used for RD production that are underutilized: soybean oil and inedible corn oil. Soybean oil estimates of available feedstock are around 2 billion gallons per year, with about 700 million gallons going into biodiesel production[17], leaving about 1.3 billion gallons available to RD production without impacting biodiesel production. Current corn ethanol production facilities are capable of extracting between 390 and 845 million gallons of inedible corn oil[18], which could be utilized for RD production. This puts the available feedstock for RD in the U.S. at about 1.7 to 2.1 billion gallons without impacting current biodiesel production or importing feedstocks from international sources. Staff projects that any growth in U.S. RD production capacity will be split 50-30-10-10 between corn oil, soybean oil, tallow, and used cooking oil (UCO), respectively.

Projected RD Production Capacity

Staff is aware of three currently announced RD plants that are not completed but are expected to be completed by 2020. These plants are:

- *AltAir:* Los Angeles, California – 40 MGPY[19]
- *Red Rock Biofuels:* Lakeview, Oregon – 16 MGPY[20]
- *Fulcrum Bioenergy:* McCarran, Nevada – 10 MGPY[21]
- *SG Preston:* South Point, Ohio – 120 MGPY ($400 million)[22]
- *East Kansas Agri Energy:* Garnett, Kansas – 3 MGPY with plans to expand to 6 MGPY[23]

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[16] http://www.epa.gov/otaq/fuels/rfsdata/2014emts.htm
[17] http://www.eia.gov/biofuels/biodiesel/production/
[18] 13 billion gallons of corn ethanol * 0.03 – 0.065 gallons corn oil per gallon corn ethanol, based on CARB GREET documents with efficiency of corn oil extraction equipment.
[19] http://www.energy.ca.gov/releases/2014_releases/2014-09-10_naturalgas_biofuels_grants.html
[20] http://www.oxfordcatalysts.com/financial/fa/ocgfa20130708.php
[21] http://www.fulcrum-bioenergy.com/facilities.html
[22] http://www.bloomberg.com/news/2014-08-01/sg-preston-to-build-400-million-renewable-diesel-plant-in-ohio.html
[23] http://ekaellc.com/renewabledieselproject

- *Emerald Biofuels:* Plaquemine, Louisiana – 88 MGPY[24]

- *Petrixo Oil and Gas:* Fujairah, United Arab Emirates – 300 MGPY ($800 million), possibly 150 MGPY as RD[25]

- *Currently Announced Additional U.S. Production Capacity:* 277 MGPY.

In addition to the planned RD plants above, staff projects that additional RD plants will come online prior to 2020. Staff projects additional U.S. production based on assumptions of low, mid and high growth rates. Low growth rate would be 50 MGPY additional capacity per year, mid growth rate is 100 MGPY, and high growth is 200 MGPY for each year from 2017 to 2020[26]. Given the assumptions above and the currently announced projects, staff's projected U.S. RD production capacity is shown in Table B-7 below.

B-7. Projected U.S. RD Production Capacity in 2020 (MGPY)

	Current Capacity	Announced Capacity	Projected Additional Capacity	Total
Low Growth	212	277	200	**689**
Mid Growth	212	277	400	**889**
High Growth	212	277	800	**1,289**

Pump Labeling Issues

Biomass-based diesel that is dispensed from a commercial pump is required by the FTC to be labeled distinctly from regular diesel in blends above 5 percent[27]. Specifically diesel fuels containing between 6 and 20 percent biomass-based diesel must be labeled as such, and diesel fuels with more than 20 percent biomass-based diesel must be labeled with their specific blend level. Both biodiesel and renewable diesel meets the definition of biomass-based diesel and are thus subject to these labeling requirements.

The labeling requirements for renewable diesel can cause difficulty in supplying higher blends of renewable diesel into the general market in a fungible way. For example, if a terminal normally distributes diesel with 5 percent or less renewable diesel, it would need to segregate additional tankage in order to ship higher blends in order to accurately inform customers of RD content for compliance with these provisions.

Staff believes there are four ways that higher blends of RD may become available within the confines of the labeling issue.

[24] https://emeraldonellc-public.sharepoint.com/projects
[25] http://honeywell.com/News/Pages/Honeywell%E2%80%99s-UOP-Green-Fuels-Technology-Selected-By-Petrixo-To-Produce-Renewable-Jet-Fuel-And-Diesel.aspx
[26] Low growth is approx. the rate of capacity increase over the last 4 years, mid growth is approx. the rate of planned increase in capacity over the next 2 years; high growth is 2x mid growth.
[27] 16 CFR 306, especially 306.10 and 306.12

- If demand becomes high enough, terminal position holders may transition to using all or nearly all R6 to R20, requiring no additional tank segregation because all diesel distributed from a terminal may be labeled as R6-R20.

- If enough terminal position holders request it, terminal operators may determine it is profitable to segregate tankage for R6 to R20.

- Renewable diesel may currently be delivered directly to fleets bypassing the need for pump labeling, allowing any blend up to and including R100 to be used.

- FTC may amend their regulations to not require labeling of renewable diesel; this could either be due to congressional direction, or FTC interpretation of the intent of the guiding statute calling for the labeling requirements[28].

Projected U.S. Supply

For this analysis, staff assumes that all of the production capacity of the current, announced, and projected U.S. RD plants, as well as the Neste Singapore plant, will be available to the U.S. market. In accordance with the preceding assumptions, staff's projections for total U.S. supply of RD in 2020 are shown in Tables B-8, B-9, and B-10 below.

B-8. U.S. Projected Supply of RD Broken Down by Feedstocks – Low Projection

Feedstock (MGPY)	Current U.S. Facilities	Announced U.S. Facilities	Projected U.S. Facilities	Current International Facilities	Total 2020 U.S. Supply
Tallow	212	28	20	240	500
Corn Oil	0	138	100	0	238
Soybean Oil	0	83	60	0	143
UCO	0	28	20	0	48
Total	212	277	200	240	**929**

B-9. U.S. Projected Supply of RD Broken Down by Feedstocks – Mid Projection

Feedstock (MGPY)	Current U.S. Facilities	Announced U.S. Facilities	Projected U.S. Facilities	Current International Facilities	Total 2020 U.S. Supply
Tallow	212	28	40	240	520
Corn Oil	0	138	200	0	338
Soybean Oil	0	83	120	0	203
UCO	0	28	40	0	68
Total	212	277	400	240	**1,129**

[28] Energy Independence and Security Act of 2007 section 205

B-10. U.S. Projected Supply of RD Broken Down by Feedstocks – High Projection

Feedstock (MGPY)	Current U.S. Facilities	Announced U.S. Facilities	Projected U.S. Facilities	Current International Facilities	Total 2020 U.S. Supply
Tallow	212	28	80	240	560
Corn Oil	0	138	400	0	538
Soybean Oil	0	83	240	0	323
UCO	0	28	80	0	108
Total	212	277	800	240	**1,529**

Summary

Staff projects there to be between **929** and **1,529** MGPY of RD supply available to the U.S. in 2020. In all cases, staff expects tallow to be the majority of the feedstock, followed by corn oil, soybean oil, and finally used cooking oil. It is expected much of this RD could potentially be available to the California fuels market depending upon LCFS credit prices. As a best estimate, staff expects approximately **400** million gallons of RD to come to California in 2020.

vii. Natural Gas

For natural gas, staff looked at a transportation demand in California rather than fuel availability. The availability of natural gas for fuel consumption is not in question because of the abundance of natural gas. The question is how much natural gas will be used by the transportation sector. To answer that question, staff looked at several reports that projected natural gas use in the transportation sector. The reports that staff studied were: 1) ICF report on the LCFS compliance outlook for 2020[29], 2) California Energy Commission 2013 Integrated Energy Policy Report[30], 3) Boston Consulting Group's Low Carbon Fuel Standard Feasibility Assessment[31], and 4) Historic Consumption data from the EIA[32]. Staff also solicited and received natural gas projections from the California Natural Gas Vehicle Coalition. The range of projections through 2020 from the studies was between approximately 600 million DGE to about 1.2 billion gallons of DGE. Recent data showed a slightly more conservative trend, so staff took a conservative approach and used the high estimate at 900 million DGE, the medium case at approximately 600 million DGE, and the low case at approximately 300 million DGE in 2020.

The low case was designed using historic EIA data plus the existing renewable natural gas data to extrapolate growth out to 2020. The high case was based on CEC's 2013

[29] "California's Low Carbon Fuel Standard: Compliance Outlook for 2020" June 2013 Prepared by ICF
[30] http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF.pdf
[31] "Low Carbon Fuel Standard Feasibility Assessment", August 29. 2013, The Boston Consulting Group
[32] http://www.eia.gov/dnav/ng/hist/na1570_sca_2a.htm

IEPR projections. The medium case was the average between the high and the low case.

B-11. Low Natural Gas Case (millions of gallons diesel gallon equivalents)

	2013	2014	2015	2016	2017	2018	2019	2020
LNG	51	58	81	86	91	97	103	109
CNG	75	92	121	128	136	145	154	164
Total	**127**	**150**	**201**	**214**	**227**	**242**	**257**	**273**

B-12. Medium Natural Gas Case (millions of gallons diesel gallon equivalents)

	2013	2014	2015	2016	2017	2018	2019	2020
LNG	51	58	88	115	145	173	203	235
CNG	75	94	132	172	218	260	305	352
Total	**127**	**152**	**221**	**287**	**364**	**433**	**508**	**587**

B-13. High Natural Gas Case (millions of gallons diesel gallon equivalents)

	2013	2014	2015	2016	2017	2018	2019	2020
LNG	51	59	96	144	200	250	304	360
CNG	75	95	144	216	300	375	456	540
Total	**127**	**154**	**240**	**360**	**500**	**625**	**760**	**900**

viii. Renewable Natural Gas

In order to get renewable natural gas projections, staff did a survey of renewable natural gas to California. Staff used data from a survey of three renewable natural gas producers that have contracts in place, projects committed, and/or completed to bring renewable natural gas to California. The survey data was used as the low case. For the high case, staff used the same ratio of renewable natural gas to natural gas as in the low case relative to the high natural gas estimates. The medium case is the average between the high and the low case.

B-14. Low Renewable Natural Gas Case (millions of gallons diesel gallon equivalents)

	2013	2014	2015	2016	2017	2018	2019	2020
LNG	3	7	27	29	32	35	38	42
CNG	3	16	41	44	48	52	57	63
Total	**7**	**23**	**68**	**73**	**80**	**87**	**96**	**105**

B-15. Medium Renewable Natural Gas Case (millions of gallons diesel gallon equivalents)

	2013	2014	2015	2016	2017	2018	2019	2020
LNG	3	7	30	39	51	63	76	90
CNG	3	18	45	59	77	94	114	136
Total	**7**	**25**	**74**	**98**	**128**	**157**	**190**	**226**

B-16. High Renewable Natural Gas Case (millions of gallons diesel gallon equivalents)

	2013	2014	2015	2016	2017	2018	2019	2020
LNG	3	8	32	49	70	90	113	139
CNG	3	19	48	74	105	136	170	208
Total	**7**	**27**	**81**	**123**	**176**	**226**	**284**	**347**

ix. Electricity and Hydrogen

Advanced Clean Car (ACC) staff estimated on-road vehicle population for both electric and hydrogen vehicles through 2030 based on requirements in the ACC regulation. From those vehicle estimates, staff determined the fuel use for both electricity and hydrogen. Hydrogen use is small but growing through 2020. However, the electricity vehicle population should exceed the expected ACC requirements through 2020.

B-17. Electricity and Hydrogen Projections

	2015	**2016**	**2017**	**2018**	**2019**	**2020**
BEVs, PHEVs and FCEVs (number vehicles)	170,000	220,000	270,000	340,000	430,000	550,000
Electricity (1000 MWh)	440	596	759	982	1,276	1629
FCVs (number vehicles)	750	2,000	5,000	12,000	21,000	33,000
Hydrogen (million kg)	0.1	0.3	0.8	2.1	3.8	6.1

B. Expected Growth of California Energy Demand for Transportation Fuels

1. Estimating the Growth in Demand for Gasoline, Diesel, and Other Liquid Fuels Regulated by the LCFS

The demand for California transportation fuel is based on an estimate of how total energy demand for fuels will change from a 2013 baseline. The 2013 baseline was derived from data reported in the LCFS LRT. Estimates for fuels typically used by light-duty vehicles (gasoline, ethanol, electricity) were combined to create an estimate of the fuel energy subject to the LCFS gasoline standard. The remaining fuels (CARB diesel, biodiesel, renewable diesel, and natural gas) were assumed to be subject to the LCFS diesel standard.

Estimates for gasoline use (assumed to be E10) in 2014 were made to reflect recent BOE data that indicates that there is likely to be almost one percent growth in E10 use between 2013 and 2014. The gasoline energy demand from 2014 onwards was then adjusted to be consistent with EIA's AEO 2014 reference case estimates of gasoline growth. These estimates were:

- Gasoline demand will decline annually by 1.1 percent between 2014 and 2020,

- Gasoline demand will decline annually by 1.5 percent between 2020 and 2025.

Diesel fuel energy demand was forecast from the 2013 data in the LCFS LRT by applying a 1.5 percent annual growth rate to that fuel[33]. This is consistent with the CEC's estimate of diesel demand in its 2013 IEPR.

2. Assessing the Role that the Increased Use of Electricity and Natural Gas are Expected to Play in Providing Energy to the Transportation Sector.

The LCFS is expected to have profound impacts on the deployment of lower CI liquid alternative fuels offered for sale in California, but relatively little impact on the gross amount of electricity, natural gas, and hydrogen used in the transportation sector. These three alternative fuels require consumers and transportation businesses to acquire vehicles capable of using these fuels. Fuel providers affected by the LCFS have relatively little influence on consumers' adoption of alternative fuel vehicles. However, as such vehicles are placed in service, they will consume fuels that create LCFS credits, and it is essential to model this effect in assessing the ability of the LCFS to meet its targets.

California's ACC and ZEV programs will be major drivers of the growth of electricity and hydrogen, and the economic advantage of natural gas relative to diesel fuel will be the major factor affecting the growth of natural gas. The impact of the ZEV program and the expected expansion of California policies that are expected to further the impact of electric and hydrogen powered vehicles was modeled on the expectation that 1.5 million such vehicles will be operating in the state by 2025.

Currently over 100,000 ZEVs are operating in the California. The "Base Case" LCFS illustrative scenario assumes that 0.55 million of the vehicles targeted for 2025 will be operating by 2020, and that the full goal will be met by 2025. In 2020, the average HEV, BEV, and HFCEV are expected to travel 10,000 miles annually on their principal fuel, and consume 1.6 million MWhs of electricity, amounting to about 0.4 percent of the energy consumed by light-duty vehicles.

California already is a leader in the use of natural gas for transportation. This fuel has been used extensively in transit fleets, port trucks, and refuse vehicles, and it is growing rapidly in other sectors. The current growth of natural gas is concentrating in the

[33] Note that the energy demand was grown. In the evaluation scenarios diesel energy demand is calculated to grow by 1.5 percent per year, but actual demand for CARB diesel will decrease with greater use of alternative fuels by HDVs.

trucking sector, and is occurring because of the natural gas' much lower energy price relative to diesel fuel. This price advantage is expected to continue well into the future. As a result, numerous recent studies[34] have indicated that the use of natural gas in California could grow by a factor of three to more than ten by as soon as 2020. Recent trends (lower oil price, slower introduction of HD NG engines) have led some to the conclusion that growth will be slower than anticipated. In light of the most recent trends, the LCFS illustrative scenario assumes that natural gas usage in California will grow more modestly than forecast just last year, and will be in the lower side of those forecasts. As a result, the "Base Case" assumes that natural gas use will grow to 300 million DGEs by 2020, and further increase to about 500 million DGEs by 2025. At these amounts, NG would grow from about three percent of the HDV fuel supply today to seven percent by 2020 and 11 percent by 2025.

C. Assessment of the Banked Credits that the Current LCFS is likely to Carry Over into 2016.

Throughout the first two and a half years of the LCFS, regulated parties (RPs) have consistently produced far more credits than required for current year compliance. As a result, collectively RPs will enter 2016 with a large inventory of banked credits. In the first half of 2014, ARB staff has observed the following trends:

- Oil refiners have, on average, used enough lower CI biofuels to meet their expected obligations;

- Imports of renewable diesel and use of natural gas continue to produce substantial amounts of credits, most of which have been transferred to other RPs;

- Supplies of low CI biomethane have grown dramatically;

- The CIs of liquid biofuels have continued to decrease; and

- Applications for new fuel pathways with lower CIs continue to be submitted in large numbers.

As a result of these trends, by the end of the second quarter 2014, accumulated credits exceeded current obligation by about four million credits, and this amount is expected to grow significantly by the end of the year. The exact amount of carry-over will not be known until March 2015 (by when all parties must file reports on credits and deficit generation for the fourth quarter of 2014) but is expected to be on the order of 5 million credits.

Additionally, substantial opportunity will exist to create additional credits throughout 2015 while the LCFS CI reduction is frozen at one percent, and fuels that provide

[34] See references 22-25 on page B-23

several times the amount of needed credits will be relatively available. Factors that would lead to an increase in credit generation for banking include the following:

- Decisions by refiners to seek the lowest CI fuels available;

- A substantial increase in credit prices, further incenting production of renewable natural gas and increased imports of renewable diesel and lower CI cane ethanol; and

- Recognition that credits will be much more valuable in the future as the LCFS increases in stringency.

While the exact impact of these factors is subject to debate, it seems clear that directionally, they should lead to greater credit accumulation in 2015 than in 2014. As a result, the "Base Case" LCFS illustrative scenarios estimate that approximately 9 million credits could be carried into 2016, the first year in which the LCFS stringency is increased beyond its currently level of one percent.

D. Evaluation of the Likely CIs of the Fuels that could be Used to Create LCFS Credits.

1. Adjustments to Current iLUC Values and other Changes Associated with Updated GREET Analyses

As part of the reassessment of the LCFS many adjustments are being made to better assess the life cycle impact of fuels regulated under the program. Most changes have relatively small effects on assessments of the ability to comply. However, some could individually have a significant effect, and collectively the changes have impacts that need to be analyzed. The following describes has this has been accomplished.

a. Changes to the CIs for CARBOB, CARB Diesel and CaRFG

Staff is proposing to update the CIs for CARBOB, CARB diesel and CaRFG as part of this rulemaking. The proposed changes affect both the standard and the calculation of credit and deficit generation by every fuel regulated under the LCFS. Thus, these changes are fundamental in the assessment of the proposed compliance curve in the LCFS illustrative scenario.

The following values are used in the LCFS illustrative scenarios beginning in 2016[35]:

- CI for CARBOB of 100.79 grams/MJ

- CI for CARB Diesel of 103.04 grams/MJ

[35] At the time analyses of the illustrative scenario was preformed ongoing refinement of these CIs was still underway, and the CIs used in this analysis may differ slightly from the values used in the proposed regulation.

- 2010 base CI for CaRFG of 98.41 grams/MJ

The 2010 base CI for CaRFG, 98.41 grams/MJ, was derived in the same manner as the current base of 95.42. The revised value represents a 2010 fuel mix that is approximately ten percent by volume ethanol, with the remainder of the fuel from CARBOB. The ethanol used in 2010 is modeled as corn-derived ethanol, 12 percent of which was from California plants with the remaining 88 percent from other U.S. production.

The revised CI for CaRFG is being proposed as the basis for the LCFS standard for the entire period from 2016 to 2025. The percent reduction used in the compliance curve for gasoline fuels (and their replacements) for a given year is applied to this value to compute the LCFS standard for that year. For example, the LCFS standard for 2020, when ten percent reduction is required, would be set at 88.47 grams/MJ (as compared with the current 2020 standard of 86.27).

b. iLUC Changes

Indirect land use effects have been incorporated into the CI values for several crop-based biofuels. As discussed in the Initial Statement of Reasons, these values have been reanalyzed, and substantial changes are being proposed. The CI values used in the LCFS illustrative scenarios reflect the anticipated changes beginning in 2016. The principal changes that are used were:

- The iLUC value for corn-derived ethanol was reduced by 10 grams/MJ,
- The iLUC value for cane-derived ethanol was reduced by 26 grams/MJ, and
- The iLUC value for soy-derived biodiesel was reduced by 35 grams/MJ

2. Assumptions Concerning Incremental Improvement of CIs with Time

Over the first three years of the LCFS, there has been a steady decline in the average CI of the mix of biofuels used in California. Concurrently, there has been a great expansion of the applications for fuel-pathway CIs. These lower CI pathways will provide additional opportunities to produce more credits per unit of fuel used. ARB staff expects these trends to continue and actually accelerate as the stringency of the LCFS increases and credits become more valuable.

A two-step process was used to reflect how the trend to lower CI fuels will impact credit generation between 2016 and 2025. First, estimates of “pool-average” CIs for fuels with many different pathways were made based on the range of fuel-pathway CIs (FPCs) approved for use in the LRT. The fuels studied were corn ethanol (150 FPCs), Cane Ethanol (21 FPCs), and Corn-Sorghum Ethanol (20 FPCs). In each case, the CIs of the lowest 50 percent of FPC CIs were averaged together, and this CI was then assigned (after appropriate adjustments to reflect iLUC changes) as the CI of that fuel category in 2016[36]. For other biofuels, a single value, or a simple average of available CIs, which generally had a much smaller number of FPCs, was used to create the 2016 CI estimate. These fuels included molasses ethanol, Corn-Sorghum-Wheat Slurry ethanol, and various biodiesels.

Once a starting point for a fuel category's CI was determined for 2016, the CI was further lowered to reflect that higher credit values and continued plant improvements will lead to lower average CI with time. A conservative adjustment of a one percent decrease in CI values for each category was uniformly applied to at least partially recognize this effect. Note that the one percent per year annual improvement did not apply to several fuels with very low 2016 CIs, nor was it applied to natural gas, cellulosic ethanol and renewable gasoline, fuels that do not yet have established CIs, and which play a relatively minor role in LCFS compliance through 2010.

The CIs for natural gas was modeled in a different manner. There is a wide range of possible CIs for natural gas depending on the sources of the gas, the distance the gas must travel to the user in California and to form of gas used, CNG or LNG. It is not known what the future mix of these factors will be. In light of this the illustrative fuel mix uses a simplified approach. Natural gas use is split into just two categories, conventional NG and renewable NG. A CI of 70 was applied to the conventional NG and a CI of 25 was used renewable NG. These values approximate the average CIs expected to be applied to these fuels.

E. Impact of other Credit-Producing Options Proposed in the Re-Adopted LCFS

1. Refinery Credits

Staff's proposal includes a mechanism that allows refiners to produce LCFS credits by investing in refinery changes that improve efficiency and reduce GHG emissions. The details of the proposal are discussed in Chapter III, Section M of the ISOR.

Currently, total GHG emissions from refining in California exceed 30 MMTs annually. Under the proposal, qualifying efficiency changes at refineries could produce LCFS credits equal to either 100 or 50 percent of the GHG reductions achieved. The extent to which this provision would be used will be affected by many factors, principally the value of LCFS credits, the cost and availability of qualifying efficiency improvements, and the desire of refiners to invest in such improvements. A wide range of credit production from this mechanism by 2020, from very little to several million MTs annually, is possible.

This mechanism is reflected as part of the LCFS illustrative scenarios at a relatively modest level. It is assumed that refiners will, on average, institute qualifying GHG

[36] For example the average CI of corn-derived ethanol under this method changes from 82.2 grams/MJ to 70.0 grams/MJ.

reduction projects that improve refining efficiency by one percent per year, starting in 2016 and continuing through the analysis period. Actual credit production was delayed to 2017 to reflect time needed to institute and qualify projects. It was assumed that half of the reductions would gain 100 percent credits, and that half would produce 50 percent. As a result, refiner credits are estimated to provide about 1.1 MMTs of credits in 2020.

2. Innovative Production Methods

The staff's proposal also includes provisions that allow oil producers to gain LCFS credits by investing in innovative production methods that reduce GHG emissions. The details of the proposal are discussed in Chapter III, Section M of the ISOR. The contribution of oil production emissions to CI for CARBOB and CARB diesel is very significant (12.71 grams/MJ is being proposed), and significant amounts of credits could be produced if qualifying innovations were to be instituted. The extent to which this provision would be used will be affected by many factors, principally the value of LCFS credits, the cost and availability of qualifying innovative techniques, and the desire of producers to invest in such improvements.

The timing and extent of qualifying innovations is not predictable at this time. As a result, credit production from this mechanism is not reflected as part of the LCFS illustrative scenarios in this analysis.

F. Factors that will Influence the Choice of Fuels Available for use Under the LCFS.

The LCFS provides RPs with great flexibility to determine the mix of fuels they will use to produce LCFS credits required for compliance. The factors that influence this choice include:

- The credit available through use of the fuel,
- The expected price of the fuel,
- The added value that the LCFS and RIN credits might bring to the fuel,
- The ability to deliver and market the fuel in California,
- The degree to which the fuel matches up with the RPs core business, and
- The desire of the RP create credits for sale or for banking for future year compliance.

The future mix of fuels also is impacted by the diverse nature of parties regulated by the LCFS. These parties include:

- Major oil companies that are responsible for an overwhelming majority of deficits producing petroleum fuels and will need self-generate or otherwise procure large amounts (individually between one to as many as eight MMTs of credits annually by 2020) of the LCFS credits needed to maintain compliance.

- Mid to large size fuel distribution companies that are responsible for modest volumes of deficit producing petroleum fuels and will need self-generate of otherwise procure modest amounts of the LCFS credits to maintain compliance.

- Large fuel marketing companies that participate in the fuel market through the buying and selling of fuels. While these entities physically do not deliver substantial volumes of fuels to market and are responsible for little, if any LCFS deficits obligations, they may become substantial actors in the buying and selling of LCFS credits.

- Companies that can become RPs for opt-in fuels, such as electricity, hydrogen and natural gas. These entities are major generators of LCFS credits and will act as producers of credits needed by RPs that incur deficit obligations from petroleum fuels.

- Biofuel producers and markets that supply lower CI fuels to California. These firms can supply credit-generating fuels to oil refiners and larger marketers, can deliver fuels directly to fleets and retail customers, and can become substantial participants in the credit trading market.

In order to produce illustrative scenarios of how the LCFS could affect fuel use over the next decade, it is necessary to model the factors that affect the choice of fuels, as well as to predict the response of the entities listed above to the LCFS. This assessment is then used to model their collective behavior of parties involved in the LCFS. The illustrative scenarios assume this behavior as follows:

- The value of LCFS credits will rise to at least the level experienced in the fall of 2013 when prices rose from $30 per credit in the first quarter of 2013 to $80 by December 2013.

- This increase in credit value is sufficient to incent:

    - The participation of virtually 100 percent of opt-in fuel providers in the market,

    - The import of low carbon fuels that are fungible in the California market and available for export,

    - The willingness of petroleum fuel providers to seek and pay for a mix of biofuels with the lowest possible CI for the fuels that they directly market, and

- o The desire of renewable fuel producers to maximize their marketing of fuels to California by securing low CI fuels and bringing them to the California market for direct delivery to users or to petroleum fuel providers.

Finally there are a number of regulatory and logistic factors that affect the deployment of otherwise available low CI fuels. These include:

- The impact of CARB fuel regulations (principally related to biodiesel),
- The impact of U.S. EPA's RFS2 rulemakings,
- Other federal requirements, such as labelling standards for biofuels, and
- Logistic concerns related to bringing fuels to California, or distributing them once they are in the State.

After considering how these factors could affect the choice of fuels used to comply with the LCFS, the following are reflected in the fuel mix used in the illustrative scenarios:

- The average CI of ethanol used in E10 or E85 will decrease with time, and ethanol volumes will grow modestly. Specifically:
  - o Available supplies of the lowest CI ethanol available for use in California will progressively be used in larger quantities as supplies become available and more LCFS credits are needed. The order of use (subject to total volume and other constraints) assumed is:
    - ▪ Cellulosic ethanol,
    - ▪ Molasses ethanol,
    - ▪ Lower-CI Cane ethanol, and
    - ▪ Lower-CI Corn and related domestic ethanol.
  - o The amount of ethanol used will be limited to:
    - ▪ The volume needed to produce E10, and
    - ▪ A growing, but relatively modest amount of E85.
  - o The total volume of ethanol used will remain stable at around 1,500 million gpy.

- The choice of biodiesel will be heavily influenced by the fuel's CI. The total amount used will be impacted by the proposed Alternative Diesel Fuel (ADF) rulemaking,

    - Available supplies of lower CI biodiesel will be used preferentially over other supplies, and

    - Total biodiesel use will grow to about five percent of total diesel volumes and then stay constant at that level, approximately 200 million gpy.

- Renewable diesel volumes will grow substantially in response to LCFS credit values and the need to produce more credits as the LCFS increases in stringency to the ten percent level by 2020. The industry and government will collectively resolve logistic and labelling factors to market renewable diesel in the range of five to up to 20 percent. LCFS credit prices will provide a sufficient price premium to induce supplies of up to 400 million gpy by 2020 and 600 million gpy by 2025.

- Natural gas use will grow steadily in response to its price advantage over conventional diesel. Use will reach 300 million DGEs per year by 2020, roughly 2.5 times the current usage reported in the LRT. By 2020, the bulk of the NG used in transportation will come from renewable sources, due to the value of LCFS credits that will incent production RNG from landfill gas, sewage digester gas, food wastes, and dairy operations.

- Electricity and hydrogen use in transportation will grow dramatically as the penetration of battery, plug-in hybrid, and fuel cell electric vehicles (BEVs, PHEVs, and FCEVs) increases in response to California's ZEV program and consumer demand. It is estimated that 550,000 of these vehicles will be in service by 2020, and the number will grow to 1.5 million by 2025.

- ARB is also proposing that users of electricity in fixed guideway transit systems and some off-road vehicles be allowed to opt into the LCFS credit. It is assumed that this will enable the estimated 900 million MWhs of electricity used by these parties to create LCFS credits beginning in 2016.

G. Construction of Illustrative Scenarios to Generate LCFS Credit and Deficit Amounts based on Anticipated Use of Low CI Fuels

The next to final step in evaluating potential compliance curves involves the use of all of the information and factors discussed above to calculates credit and deficit generation based on use of the fuel volumes and fuel CIs developed in previous steps. This assessment employs an excel spreadsheet to calculate how these inputs interact to produce the credits needed to meet the LCFS reduction requirements. The products are year-by-year estimates of credits and deficits and a comparison of those estimates to potential compliance curves targeted at achieving a ten percent CI reduction by 2020.

The analysis period covers ten years from 2016 through 2025. Per the proposed rule, the LCFS is set at ten percent in the 2020 to 2025 timeframe to determine the viability of maintaining at least a ten percent reduction beyond 2020. Note that in light of an anticipated statewide GHG 2030 target that is significantly lower than the AB 32 goal for 2020, it is expected that ARB will revisit the LCFS standard before 2020 to establish greater reductions targets for the 2021-2030 period.

ARB staff used the assessment to develop an estimate of an illustrative mix of fuels that could be used pursuant to the LCFS. This illustrative mix is summarized below in Tables B-18 and B-19, which shows fuel amounts from 214 through 2020.

Table B-18. Illustrative California Reformulated Gasoline Oxygenates and Substitute Fuels through 2020

Fuel	Units	2014	2015	2016	2017	2018	2019	2020
Corn & Related Ethanol	mm gal	1,400	1,350	1,250	1,175	1,000	925	875
Cane and Sugar Ethanol	mm gal	120	170	240	290	410	460	510
Cellulosic Ethanol	mm gal	0	0	5	15	50	75	100
Renewable Gasoline	mm gal	0	0	0	0	5	15	25
Hydrogen	mm gal GGE	0.03	0.4	1	2	4	5	7
Electricity for LDVs	mm gal GGE	9	14	19	24	31	40	51
Notes: mm gal = million gallons; GGE = gasoline gallon equivalent								

Table B-19. Illustrative Alternative Diesel Fuel Source Types through 2020

Fuel	Units	2014	2015	2016	2017	2018	2019	2020
Biodiesel	mm gal	72	97	129	160	180	180	180
Renewable Diesel	mm gal	120	180	250	300	320	360	400
Conventional NG	mm gal DGE	70	80	80	80	80	80	60
Renewable NG	mm gal DGE	50	60	80	100	140	180	240
Electricity for HDVs/Rail	mm gal DGE	0	0	24	24	24	24	24
Total biodiesel %		1.99%	2.65%	3.51%	4.30%	4.81%	4.79%	4.76%
Renewable Diesel %		3.3%	4.9%	6.8%	8.1%	8.6%	9.6%	10.6%
Notes: NG = natural gas; HDVs = heavy-duty vehicles; mm gal = million gallons; DGE = diesel gallon equivalent;								

The fuel mix shown in Tables B-18 and B-19 was then used to evaluate several compliance curves that target reaching a ten percent LCFS reduction goal in 2020. This analysis was performed for three different trajectories that staff believe best bound the available options. These were:

- Option 1 -- Use the percent reductions in the existing rule to define standards for 2016 to 2020,
- Option 2 -- Use a straight line to go from a one percent standard in 2015 to ten percent in 2020, and
- Option 3 -- Use a more gradual approach from a one percent standard in 2015 to ten percent in 2020

Table B-20 below provides the percent reductions for the three cases:

Table B–20. Percent Reductions Analyzed

Year	Original Reduction Percent	Straight Line Reduction Percent	Gradual Reduction Percent
2016	3.5 percent	2.75 percent	2.0 percent
2017	5.0 percent	4.5 percent	3.5 percent
2018	6.5 percent	6.25 percent	5.0 percent
2019	8.0 percent	8.0 percent	7.5 percent
2020 onwards	10.0 percent	10.0 percent	10.0 percent

A summary of the results of this analysis are presented in section H, below, and complete copies of the output are included in Tables B- 22, B-23 and B-24

H. Recommendation of Compliance Curve for Revised LCFS

Each option produces sufficient credits to enable compliance through 2019, and Options 2 and 3 show sufficient credits availability through 2020. By 2022, all options show annual reductions in excess of the ten percent reduction requirement.

Annual credit production in all scenarios is less than needed to offset annual deficit creation in a three- to five-year period around 2020. Therefore, compliance in 2020 and at least three years around 2020 requires that banked credits be used. However, due to the difference in banked credits achieved in the three approaches, only the Option 3 (the gradual path compliance curve) provides sufficient credits to allow compliance by all parties throughout the 2020 in the 2025 period.

Table B-21 below provides the credit balances at the end of each year for the three compliance curves that were modeled:

Table B-21. Million Metric Tons of Banked LCFS Credits at End of Year

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Option 1	9.4	8.3	5.9	1.9	-4.3	-7.3	-7.9	-6.2	-2.5	3.3
Option 2	11.0	11.0	9.1	5.2	-1.0	-4.1	-4.7	-3.0	0.8	6.5
Option 3	12.7	14.8	15.6	12.7	6.5	3.5	2.8	4.6	8.3	14.1

Even Option 3, the gradual path compliance curve, results in a tight compliance situation in the 2020 to 2023 period, a timeframe during which the quantity of banked credits available for year-to-year carry-over is a relatively small fraction of the next year's cumulative compliance obligation. For example in the 2020 and beyond approximately 20 million credits will need to be retired to meet all of the regulated parties' compliance obligations. Under Option 3 the size of the credit year-to-year carry over is less than 15 percent of the obligation.

In addition to current year compliance, a supply of extra credits is equally important to producing a liquid and competitive credit market. It is likely that some parties with large compliance obligations will seek to build and maintain substantial amounts of banked credits to ensure future compliance. These credits will not be available for transfer.

ARB staff believes it is necessary to maintain a significant quantity of credits, significantly above the total than just needed for compliance (a situation that relies on all excess credits being available for transfer to others). With the fuel mix used in the illustrative scenarios, only Option 3, employing the "Gradual Path" compliance curve, provides this buffer. For this reason the "Gradual Path" compliance curve is being proposed as the revised compliance curve.

As previously stated, many other mixes of low CI fuels and innovative credit creation are possible. Mixes that includes substantially greater amounts of such fuels and credits could result in response to the LCFS. It is also possible that some of the low CI fuel penetration rates assumed in the illustrative scenarios will occur more slowly than modelled, and that generation of the needed credits will occur more slowly than modelled.

Table B - 22 Analysis of Proposed Compliance Curve

	2010 Baseline CI	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Gasoline Std	**99.18**	97.96	97.96	97.20	95.71	94.22	91.74	89.26	89.26	89.26	89.26	89.26	89.26
Diesel Std	**102.82**	97.05	97.05	100.76	99.22	97.68	95.11	92.54	92.54	92.54	92.54	92.54	92.54
	CI Reduction	1.00%	1.00%	2.00%	3.50%	5.00%	7.50%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
	Gasoline Demand	14,469	14,324	14,181	14,039	13,899	13,760	13,622	13,418	13,216	13,018	12,823	12,630
	Diesel Demand	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
	Electricity Use - Mn MWh	0.3	0.4	0.6	0.8	1.0	1.3	1.6	2.1	2.6	3.1	3.8	4.4
	MMTs of Credit - End of Year	**5.5**	**9.2**	**12.6**	**14.7**	**15.4**	**12.5**	**6.2**	**3.2**	**2.5**	**4.1**	**7.8**	**13.5**

Fuel Volumes Table

	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	mm gal	1,250	1,200	1,100	1,000	825	750	700	600	550	475	400	320
Cane Ethanol	mm gal	100	150	200	250	350	400	450	500	500	500	500	500
Sorghum/Corn Ethanol	mm gal	100	100	100	100	100	100	100	100	100	100	100	100
Misc Corn Ethanol	mm gal	0	0	0	0	0	0	0	0	0	0	0	0
Sorghum/Corn/Wheat Ethanol	mm gal	50	50	50	75	75	75	75	75	75	75	75	75
Cellulosic Ethanol	mm gal	0	0	5	15	50	75	100	200	250	300	350	400
Molasses Ethanol	mm gal	20	20	40	40	60	60	60	60	60	60	60	60
Renewable Gasoline	mm gal	0	0	0	0	5	15	25	50	100	150	200	250
Hydrogen	mm KG (=~GGEs)	0	0	1	2	4	5	7	10	13	16	21	27
Electricity for LDVs	1000 MWH	294	440	596	759	982	1,276	1,629	2,064	2,563	3,127	3,757	4,374
Total Ethanol	mm gal	1,520	1,520	1,495	1,480	1,460	1,460	1,485	1,535	1,535	1,510	1,485	1,455
CARBOB (energy adjusted)	mm gal	12,952	12,796	12,658	12,513	12,361	12,185	11,986	11,682	11,383	11,096	10,806	10,519
Gasoline As CARFG + E85	mm gal	14,472	14,316	14,153	13,993	13,826	13,660	13,496	13,267	13,018	12,756	12,491	12,224
Ethanol	mm gal	10.50%	10.62%	10.56%	10.58%	10.56%	10.69%	11.00%	11.57%	11.79%	11.84%	11.89%	11.90%

	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Biodiesel	mm gal	72	97	129	160	180	180	180	185	185	185	190	190
Renewable Diesel	mm gal	120	180	250	300	320	360	400	500	550	600	600	600
Conventional Natural Gas	mm gal DGE	70	80	80	80	80	80	60	40	40	40	40	40
Renewable Natural Gas	mm gal DGE	50	60	80	100	140	180	240	300	340	380	420	460
Electricity for HDVs/Rail	1000 MWH	0	0	900	900	900	900	900	900	900	900	900	900
Total HD NG (DGEs)	mm gal DGE	120	140	160	180	220	260	300	340	380	420	460	500
Total Biodiesel (MM gal.)	mm gal	72	97	129	160	180	180	180	185	185	185	190	190
Diesel (non-adjusted)	mm gal	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
Diesel (energy adjusted)	mm gal	3,429	3,383	3,299	3,260	3,240	3,221	3,202	3,122	3,096	3,071	3,090	3,115
Total biodiesel %		**1.99%**	**2.65%**	**3.51%**	**4.30%**	**4.81%**	**4.79%**	**4.76%**	**4.86%**	**4.83%**	**4.80%**	**4.90%**	**4.87%**
Renewable Diesel %		**3.31%**	**4.92%**	**6.80%**	**8.07%**	**8.56%**	**9.57%**	**10.58%**	**13.13%**	**14.36%**	**15.56%**	**15.46%**	**15.36%**

Average Annual . CI Assumptions for Each Fuel (g/MJ)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	82.2	82.2	70.0	69.3	68.6	67.9	67.2	66.6	65.9	65.2	64.6	63.9
Cane Ethanol	72.5	72.5	40.0	39.5	39.0	38.5	38.0	37.5	37.0	36.5	36.0	35.5
Sorghum/Corn Ethanol	79.1	79.1	70.0	69.3	68.6	67.9	67.2	66.6	65.9	65.2	64.6	63.9
Misc Corn Ethanol	91.5	91.5	70.0	69.3	68.6	67.9	67.2	66.6	65.9	65.2	64.6	63.9
Sorghum/Corn/Wheat Ethanol	72.8	72.8	65.0	64.4	63.7	63.1	62.4	61.8	61.2	60.6	60.0	59.4
Cell. Ethanol[1]	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Molasses Ethanol	22.1	22.1	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Renewable Gasoline[2]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Hydrogen	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9
Electricity for LDVs	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Avg Biodiesel CI	15.5	14.0	12.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Renewable Diesel	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Avg of LNG&CNG	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Renewable NG	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Electricity for HDVs/Rail	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9
CARBOB	99.2	99.2	100.58	100.58	100.58	100.58	100.58	100.58	100.58	100.58	100.58	100.58
CARB Diesel	98.0	98.0	102.82	102.82	102.82	102.82	102.82	102.82	102.82	102.82	102.82	102.82

MMTs of Credits or Deficits

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	1.60	1.54	2.44	2.15	1.72	1.46	1.26	1.11	1.05	0.93	0.80	0.66
Cane Ethanol	0.21	0.31	0.93	1.15	1.58	1.74	1.88	2.11	2.13	2.15	2.17	2.19
Sorghum/Corn Ethanol	0.15	0.15	0.22	0.22	0.21	0.19	0.18	0.18	0.19	0.20	0.20	0.21
Misc Corn Ethanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sorghum/Corn/Wheat Ethanol	0.10	0.13	0.13	0.20	0.19	0.18	0.18	0.19	0.19	0.20	0.20	0.20
Cellulosic Ethanol	0.00	0.00	0.03	0.09	0.30	0.44	0.56	1.13	1.41	1.69	1.98	2.26
Molasses Ethanol	0.12	0.12	0.24	0.24	0.35	0.34	0.32	0.32	0.32	0.32	0.32	0.32
Renewable Gasoline	0.00	0.00	0.00	0.00	0.04	0.10	0.16	0.32	0.65	0.97	1.30	1.62
Hydrogen	0.00	0.01	0.01	0.03	0.06	0.08	0.11	0.15	0.19	0.24	0.31	0.40
Electricity for LDVs	0.24	0.36	0.48	0.60	0.76	0.95	1.17	1.48	1.83	2.24	2.69	3.13
Total Gasoline Side Credits	2.43	2.63	4.50	4.67	5.20	5.48	5.82	6.99	7.96	8.94	9.97	10.99
CARBOB Deficits	-1.89	-1.87	-5.12	-7.29	-9.40	-12.87	-16.22	-15.81	-15.40	-15.01	-14.62	-14.23
Biodiesel	0.74	1.02	1.44	1.82	2.01	1.95	1.90	1.95	1.95	1.95	2.00	2.00
Renewable Diesel	0.97	1.45	2.13	2.50	2.60	2.81	2.98	3.73	4.10	4.48	4.48	4.48
Conv. Natural Gas	0.25	0.29	0.33	0.31	0.30	0.27	0.18	0.12	0.12	0.12	0.12	0.12
Renewable NG	0.48	0.58	0.82	1.00	1.37	1.70	2.18	2.72	3.09	3.45	3.81	4.18
Electricity for HDVs/Rail	0.00	0.00	0.21	0.21	0.20	0.20	0.19	0.19	0.19	0.19	0.19	0.19
Total Diesel Side Credits	2.45	3.34	4.94	5.84	6.48	6.92	7.43	8.71	9.45	10.18	10.60	10.96
Diesel Deficits	-0.45	-0.45	-0.91	-1.58	-2.24	-3.34	-4.43	-4.32	-4.28	-4.25	-4.27	-4.31
Annual Credit Balance	2.54	3.65	3.40	2.10	0.73	-2.91	-6.27	-3.07	-0.69	1.67	3.70	5.67
Refinery Credits	0.00	0.00	0.00	0.45	0.68	0.90	1.13	1.35	1.58	1.80	2.03	2.25
Total Credits	4.88	5.97	9.43	10.96	12.36	13.30	14.38	17.05	18.99	20.92	22.59	24.21
Total Deficits	-2.34	-2.31	-6.03	-8.86	-11.64	-16.21	-20.64	-20.12	-19.68	-19.26	-18.89	-18.54
Credit Bank (Banked Credit Balance up to 2013 =1.35)	**5.5**	**9.2**	**12.6**	**14.7**	**15.4**	**12.5**	**6.2**	**3.2**	**2.5**	**4.1**	**7.8**	**13.5**

Table B - 23 Analysis of "Straight Line" Compliance Curve

	2010 Baseline CI	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Gasoline Std	**99.18**	97.96	97.96	96.45	94.72	92.98	91.25	89.26	89.26	89.26	89.26	89.26	89.26
Diesel Std	**102.82**	97.05	97.05	99.99	98.19	96.39	94.59	92.54	92.54	92.54	92.54	92.54	92.54
	CI Reduction	1.00%	1.00%	2.75%	4.50%	6.25%	8.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
	Gasoline Demand	14,469	14,324	14,181	14,039	13,899	13,760	13,622	13,418	13,216	13,018	12,823	12,630
	Diesel Demand	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
Electricity Use - Mn MWh		**0.3**	**0.4**	**0.6**	**0.8**	**1.0**	**1.3**	**1.6**	**2.1**	**2.6**	**3.1**	**3.8**	**4.4**
Summary Results - End-of-Tear Credits - MMTs		**5.5**	**9.2**	**11.0**	**10.9**	**9.0**	**5.0**	**-1.3**	**-4.4**	**-5.1**	**-3.4**	**0.3**	**6.0**

Fuel Volumes Table

	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	mm gal	1,250	1,200	1,100	1,000	825	750	700	600	550	475	400	320
Cane Ethanol	mm gal	100	150	200	250	350	400	450	500	500	500	500	500
Sorghum/Corn Ethanol	mm gal	100	100	100	100	100	100	100	100	100	100	100	100
Misc Corn Ethanol	mm gal	0	0	0	0	0	0	0	0	0	0	0	0
Sorghum/Corn/Wheat Ethanol	mm gal	50	50	50	75	75	75	75	75	75	75	75	75
Cellulosic Ethanol	mm gal	0	0	5	15	50	75	100	200	250	300	350	400
Molasses Ethanol	mm gal	20	20	40	40	60	60	60	60	60	60	60	60
Renewable Gasoline	mm gal	0	0	0	0	5	15	25	50	100	150	200	250
Hydrogen	mm KG (=~GGEs)	0.0	0.4	0.7	1.8	3.6	5.5	7.3	10.0	12.7	16.4	20.9	27.3
Electricity for LDVs	1000 MWH	294	440	596	759	982	1,276	1,629	2,064	2,563	3,127	3,757	4,374
Total Ethanol	mm gal	1,520	1,520	1,495	1,480	1,460	1,460	1,485	1,535	1,535	1,510	1,485	1,455
CARBOB (energy adjusted)	mm gal	12,952	12,796	12,658	12,513	12,361	12,185	11,986	11,682	11,383	11,096	10,806	10,519
Gasoline As CARFG + E85	mm gal	14,472	14,316	14,153	13,993	13,826	13,660	13,496	13,267	13,018	12,756	12,491	12,224
Ethanol	mm gal	10.50%	10.62%	10.56%	10.58%	10.56%	10.69%	11.00%	11.57%	11.79%	11.84%	11.89%	11.90%

	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Biodiesel	mm gal	72	97	129	160	180	180	180	185	185	185	190	190
Renewable Diesel	mm gal	120	180	250	300	320	360	400	500	550	600	600	600
Conventional NG	mm gal DGE	70	80	80	80	80	80	60	40	40	40	40	40
Renewable NG	mm gal DGE	50	60	80	100	140	180	240	300	340	380	420	460
Electricity for HDVs/Rail	1000 MWH	0	0	900	900	900	900	900	900	900	900	900	900
Total HD NG (DGEs)	mm gal DGE	120	140	160	180	220	260	300	340	380	420	460	500
Total Biodiesel (MM gal.)	mm gal	72	97	129	160	180	180	180	185	185	185	190	190
Diesel (non-adjusted)	mm gal	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,081	4,081	4,081	4,081	4,081
Diesel (energy adjusted)	mm gal	3,429	3,383	3,299	3,260	3,240	3,221	3,202	3,122	3,096	3,071	3,090	3,115
Total biodiesel %		**1.99%**	**2.65%**	**3.51%**	**4.30%**	**4.81%**	**4.79%**	**4.76%**	**4.86%**	**4.83%**	**4.80%**	**4.90%**	**4.87%**
Renewable Diesel %		**3.31%**	**4.92%**	**6.80%**	**8.07%**	**8.56%**	**9.57%**	**10.58%**	**13.13%**	**14.36%**	**15.56%**	**15.46%**	**15.36%**

Average Annual . CI Assumptions for Each Fuel (g/MJ)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	82.24	82.24	70.00	69.30	68.61	67.92	67.24	66.57	65.90	65.24	64.59	63.95
Cane Ethanol	72.51	72.51	40.00	39.50	39.00	38.50	38.00	37.50	37.00	36.50	36.00	35.50
Sorghum/Corn Ethanol	79.10	79.10	70.00	69.30	68.61	67.92	67.24	66.57	65.90	65.24	64.59	63.95
Misc Corn Ethanol	91.52	91.52	70.00	69.30	68.61	67.92	67.24	66.57	65.90	65.24	64.59	63.95
Sorghum/Corn/Wheat Ethanol	72.80	72.80	65.00	64.35	63.71	63.07	62.44	61.81	61.20	60.58	59.98	59.38
Cell. Ethanol[1]	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Molasses Ethanol	22.09	22.09	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00
Renewable Gasoline[2]	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
Hydrogen	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87
Electricity for LDVs	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80
Biodiesel	15.50	14.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Renewable Diesel	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
Conventional NG	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00
Renewable NG	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
Electricity for HDVs/Rail	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90
CARBOB	99.18	99.18	100.58	100.58	100.58	100.58	100.58	100.58	100.58	100.58	100.58	100.58
CARB Diesel	98.03	98.03	102.82	102.82	102.82	102.82	102.82	102.82	102.82	102.82	102.82	102.82

MMTs of Credits or Deficits

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	1.60	1.54	2.37	2.07	1.64	1.43	1.26	1.11	1.05	0.93	0.80	0.66
Cane Ethanol	0.21	0.31	0.92	1.13	1.54	1.72	1.88	2.11	2.13	2.15	2.17	2.19
Sorghum/Corn Ethanol	0.15	0.15	0.22	0.21	0.20	0.19	0.18	0.18	0.19	0.20	0.20	0.21
Misc Corn Ethanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sorghum/Corn/Wheat Ethanol	0.10	0.13	0.13	0.19	0.18	0.18	0.18	0.19	0.19	0.20	0.20	0.20
Cellulosic Ethanol	0.00	0.00	0.03	0.09	0.30	0.44	0.56	1.13	1.41	1.69	1.98	2.26
Molasses Ethanol	0.12	0.12	0.24	0.23	0.34	0.33	0.32	0.32	0.32	0.32	0.32	0.32
Renewable Gasoline	0.00	0.00	0.00	0.00	0.03	0.10	0.16	0.32	0.65	0.97	1.30	1.62
Hydrogen	0.00	0.01	0.01	0.03	0.06	0.08	0.11	0.15	0.19	0.24	0.31	0.40
Electricity for LDVs	0.24	0.36	0.48	0.59	0.75	0.94	1.17	1.48	1.83	2.24	2.69	3.13
Total Gasoline Side Credits	2.43	2.63	4.40	4.54	5.04	5.41	5.82	6.99	7.96	8.94	9.97	10.99
CARBOB Deficits	-1.89	-1.87	-6.25	-8.77	-11.23	-13.60	-16.22	-15.81	-15.40	-15.01	-14.62	-14.23
Biodiesel	0.74	1.02	1.43	1.80	1.98	1.94	1.90	1.95	1.95	1.95	2.00	2.00
Renewable Diesel	0.97	1.45	2.11	2.46	2.55	2.78	2.98	3.73	4.10	4.48	4.48	4.48
Conventional NG	0.25	0.29	0.32	0.30	0.28	0.26	0.18	0.12	0.12	0.12	0.12	0.12
Renewable NG	0.48	0.58	0.81	0.98	1.34	1.68	2.18	2.72	3.09	3.45	3.81	4.18
Electricity for HDVs/Rail	0.00	0.00	0.21	0.21	0.20	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Total Diesel Side Credits	2.45	3.34	4.88	5.75	6.36	6.87	7.43	8.71	9.45	10.18	10.60	10.96
Diesel Deficits	-0.45	-0.45	-1.25	-2.03	-2.80	-3.56	-4.43	-4.32	-4.28	-4.25	-4.27	-4.31
Annual Credit Balance	2.54	3.65	1.78	-0.06	-1.95	-3.98	-6.27	-3.07	-0.69	1.67	3.70	5.67
Refinery Credits	0.00	0.00	0.00	0.45	0.68	0.90	1.13	1.35	1.58	1.80	2.03	2.25
Total Credits	4.88	5.97	9.28	10.74	12.07	13.18	14.38	17.05	18.99	20.92	22.59	24.21
Total Deficits	-2.34	-2.31	-7.50	-10.80	-14.03	-17.16	-20.64	-20.12	-19.68	-19.26	-18.89	-18.54
Credit Bank (Banked Credit Balance up to 2013 =1.35)	**5.5**	**9.2**	**11.0**	**10.9**	**9.0**	**5.0**	**-1.3**	**-4.4**	**-5.1**	**-3.4**	**0.3**	**6.0**

Table B - 24 Analysis of "Current Rule Percent Reductions" Compliance Curve

	2010 Baseline CI	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Gasoline Std	**99.18**	97.96	97.96	95.71	94.22	92.73	91.25	89.26	89.26	89.26	89.26	89.26	89.26
Diesel Std	**102.82**	97.05	97.05	99.22	97.68	96.14	94.59	92.54	92.54	92.54	92.54	92.54	92.54
	CI Reduction	1.00%	1.00%	3.50%	5.00%	6.50%	8.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
	Gasoline Demand	14,469	14,324	14,181	14,039	13,899	13,760	13,622	13,418	13,216	13,018	12,823	12,630
	Diesel Demand	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
Electricity Use - Mn MWh		**0.3**	**0.4**	**0.6**	**0.8**	**1.0**	**1.3**	**1.6**	**2.1**	**2.6**	**3.1**	**3.8**	**4.4**
Summary Results - End-of-Tear Credits - MMTs		**5.5**	**9.2**	**9.3**	**8.2**	**5.7**	**1.7**	**-4.5**	**-7.6**	**-8.3**	**-6.6**	**-2.9**	**2.7**

Fuel Volumes Table

	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	mm gal	1,250	1,200	1,100	1,000	825	750	700	600	550	475	400	320
Cane Ethanol	mm gal	100	150	200	250	350	400	450	500	500	500	500	500
Sorghum/Corn Ethanol	mm gal	100	100	100	100	100	100	100	100	100	100	100	100
Misc Corn Ethanol	mm gal	0	0	0	0	0	0	0	0	0	0	0	0
Sorghum/Corn/Wheat Ethanol	mm gal	50	50	50	75	75	75	75	75	75	75	75	75
Cellulosic Ethanol	mm gal	0	0	5	15	50	75	100	200	250	300	350	400
Molasses Ethanol	mm gal	20	20	40	40	60	60	60	60	60	60	60	60
Renewable Gasoline	mm gal	0	0	0	0	5	15	25	50	100	150	200	250
Hydrogen	mm KG (=~GGEs)	0.0	0.4	0.7	1.8	3.6	5.5	7.3	10.0	12.7	16.4	20.9	27.3
Electricity for LDVs	1000 MWH	294	440	596	759	982	1,276	1,629	2,064	2,563	3,127	3,757	4,374
Total Ethanol	mm gal	1,520	1,520	1,495	1,480	1,460	1,460	1,485	1,535	1,535	1,510	1,485	1,455
CARBOB (energy adjusted)	mm gal	12,952	12,796	12,658	12,513	12,361	12,185	11,986	11,682	11,383	11,096	10,806	10,519
Gasoline As CARFG + E85	mm gal	14,472	14,316	14,153	13,993	13,826	13,660	13,496	13,267	13,018	12,756	12,491	12,224
Ethanol	mm gal	10.50%	10.62%	10.56%	10.58%	10.56%	10.69%	11.00%	11.57%	11.79%	11.84%	11.89%	11.90%

	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Biodiesel	mm gal	72	97	129	160	180	180	180	185	185	185	190	190
Renewable Diesel	mm gal	120	180	250	300	320	360	400	500	550	600	600	600
Conventional NG	mm gal DGE	70	80	80	80	80	80	60	40	40	40	40	40
Renewable NG	mm gal DGE	50	60	80	100	140	180	240	300	340	380	420	460
Electricity for HDVs/Rail	1000 MWH	0	0	900	900	900	900	900	900	900	900	900	900
Total HD NG (DGEs)	mm gal DGE	120	140	160	180	220	260	300	340	380	420	460	500
Total Biodiesel (MM gal.)	mm gal	72	97	129	160	180	180	180	185	185	185	190	190
Diesel (non-adjusted)	mm gal	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,081	4,081	4,081	4,081	4,081
Diesel (energy adjusted)	mm gal	3,429	3,383	3,299	3,260	3,240	3,221	3,202	3,122	3,096	3,071	3,090	3,115
Total biodiesel %		**1.99%**	**2.65%**	**3.51%**	**4.30%**	**4.81%**	**4.79%**	**4.76%**	**4.86%**	**4.83%**	**4.80%**	**4.90%**	**4.87%**
Renewable Diesel %		**3.31%**	**4.92%**	**6.80%**	**8.07%**	**8.56%**	**9.57%**	**10.58%**	**13.13%**	**14.36%**	**15.56%**	**15.46%**	**15.36%**

Average Annual . CI Assumptions for Each Fuel (g/MJ)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	82.24	82.24	70.00	69.30	68.61	67.92	67.24	66.57	65.90	65.24	64.59	63.95
Cane Ethanol	72.51	72.51	40.00	39.50	39.00	38.50	38.00	37.50	37.00	36.50	36.00	35.50
Sorghum/Corn Ethanol	79.10	79.10	70.00	69.30	68.61	67.92	67.24	66.57	65.90	65.24	64.59	63.95
Misc Corn Ethanol	91.52	91.52	70.00	69.30	68.61	67.92	67.24	66.57	65.90	65.24	64.59	63.95
Sorghum/Corn/Wheat Ethanol	72.80	72.80	65.00	64.35	63.71	63.07	62.44	61.81	61.20	60.58	59.98	59.38
Cell. Ethanol[1]	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Molasses Ethanol	22.09	22.09	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00
Renewable Gasoline[2]	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
Hydrogen	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87	43.87
Electricity for LDVs	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80	30.80
Biodiesel Average CI	15.50	14.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Renewable Diesel	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
Conventional NG	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00
Renewable NG	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
Electricity for HDVs/Rail	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90
CARBOB	99.18	99.18	100.58	100.58	100.58	100.58	100.58	100.58	100.58	100.58	100.58	100.58
CARB Diesel	98.03	98.03	102.82	102.82	102.82	102.82	102.82	102.82	102.82	102.82	102.82	102.82

MMTs of Credits or Deficits

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	1.60	1.54	2.31	2.03	1.62	1.43	1.26	1.11	1.05	0.93	0.80	0.66
Cane Ethanol	0.21	0.31	0.91	1.12	1.53	1.72	1.88	2.11	2.13	2.15	2.17	2.19
Sorghum/Corn Ethanol	0.15	0.15	0.21	0.20	0.20	0.19	0.18	0.18	0.19	0.20	0.20	0.21
Misc Corn Ethanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sorghum/Corn/Wheat Ethanol	0.10	0.13	0.13	0.19	0.18	0.18	0.18	0.19	0.19	0.20	0.20	0.20
Cellulosic Ethanol	0.00	0.00	0.03	0.09	0.30	0.44	0.56	1.13	1.41	1.69	1.98	2.26
Molasses Ethanol	0.12	0.12	0.24	0.23	0.34	0.33	0.32	0.32	0.32	0.32	0.32	0.32
Renewable Gasoline	0.00	0.00	0.00	0.00	0.03	0.10	0.16	0.32	0.65	0.97	1.30	1.62
Hydrogen	0.00	0.01	0.01	0.03	0.06	0.08	0.11	0.15	0.19	0.24	0.31	0.40
Electricity for LDVs	0.24	0.36	0.47	0.59	0.74	0.94	1.17	1.48	1.83	2.24	2.69	3.13
Total Gasoline Side Credits	2.43	2.63	4.30	4.48	5.01	5.41	5.82	6.99	7.96	8.94	9.97	10.99
CARBOB Deficits	-1.89	-1.87	-7.37	-9.51	-11.59	-13.60	-16.22	-15.81	-15.40	-15.01	-14.62	-14.23
Biodiesel	0.74	1.02	1.42	1.79	1.98	1.94	1.90	1.95	1.95	1.95	2.00	2.00
Renewable Diesel	0.97	1.45	2.08	2.44	2.54	2.78	2.98	3.73	4.10	4.48	4.48	4.48
Conventional NG	0.25	0.29	0.31	0.30	0.28	0.26	0.18	0.12	0.12	0.12	0.12	0.12
Renewable NG	0.48	0.58	0.80	0.98	1.34	1.68	2.18	2.72	3.09	3.45	3.81	4.18
Electricity for HDVs/Rail	0.00	0.00	0.21	0.20	0.20	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Total Diesel Side Credits	2.45	3.34	4.82	5.71	6.33	6.87	7.43	8.71	9.45	10.18	10.60	10.96
Diesel Deficits	-0.45	-0.45	-1.60	-2.25	-2.91	-3.56	-4.43	-4.32	-4.28	-4.25	-4.27	-4.31
Annual Credit Balance	2.54	3.65	0.16	-1.13	-2.49	-3.98	-6.27	-3.07	-0.69	1.67	3.70	5.67
Refinery Credits	0.00	0.00	0.00	0.45	0.68	0.90	1.13	1.35	1.58	1.80	2.03	2.25
Total Credits	4.88	5.97	9.13	10.63	12.02	13.18	14.38	17.05	18.99	20.92	22.59	24.21
Total Deficits	-2.34	-2.31	-8.97	-11.77	-14.51	-17.16	-20.64	-20.12	-19.68	-19.26	-18.89	-18.54
Credit Bank (Banked Credit Balance up to 2013 =1.35)	**5.5**	**9.2**	**9.3**	**8.2**	**5.7**	**1.7**	**-4.5**	**-7.6**	**-8.3**	**-6.6**	**-2.9**	**2.7**