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This chapter addresses technology and supply, one of the topics of review required by the LCFS regulation. There are several sections that are still under review by ARB staff with assistance from interested panelists. After this draft is completed, the Panel will have another opportunity to comment. This review will happen when this section is consolidated into a draft report that is expected to be released to the Panel in October, prior to its meeting.

When drafting this chapter, staff used the workplan as guidance; however, since there are similar and overlapping topics among the areas of review called out in the regulation, this chapter represents a grouping of similar topics. This chapter specifically attempts to answer the questions related to technology advances since the last staff report; supply and availability of LCFS fuels; the impact of the LCFS on state fuel supplies; the concept of ultralow carbon fuel provisions; the advisability of including provisions for those fuels; and possible ways to incentivize those fuels.

### **IV. Technology Assessment, Supply, and Availability**

#### *A. Introduction*

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

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

“Scope of each review shall include, at a minimum, consideration of the following areas:

- (4) Advances in fuels and production technologies, including the feasibility and cost-effectiveness of such advances;
- (5) The availability and use of ultralow carbon fuels to achieve the LCFS standards and advisability of establishing additional mechanisms to incentivize the use of higher volumes of these fuels;
- (6) An assessment of supply availabilities and the rates of commercialization of fuels and vehicles;
- (7) The LCFS program’s impact on the State’s fuel supplies; and

- (11) Identification of hurdles or barriers (e.g., permitting issues, infrastructure adequacy, research funds) and recommendations for addressing such hurdles or barriers”

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

This section addresses the current state of technology, the past and projected consumption or availability of fuel, past and projected vehicle populations, status of infrastructure, and any hurdles or barriers that the fuels might be encountering when trying to enter California’s transportation fuels market, where data is available. This section is organized on a fuel-by-fuel basis.

*1. Gasoline*

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

*a. Historic consumption*

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

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

**Table IV-X:** Gasoline Consumption in California, 2006-2010

*b. Future demand*

The table below shows projected California gasoline consumption based on the Low and High Petroleum Demand cases from the CEC’s 2009 Integrated Energy Policy

Report (IEPR). The high petroleum demand case represents primarily faster economic recovery and low crude prices. The low petroleum demand case represents primarily increases in fuel efficiency and lower alternative fuel prices. Due to policies favoring low-carbon fuels and technology advancements, the long-term projected trend for gasoline demand decreases.

Year	Gasoline Low (Million Gallons)	Gasoline High (Million Gallons)
2011	14,770	15,240
2012	15,040	15,630
2013	15,390	16,110
2014	15,440	16,230
2015	15,130	15,970
2016	14,770	15,670
2017	14,360	15,330
2018	13,910	14,940
2019	13,510	14,580
2020	13,110	14,170

**Table IV-X: Projected Gasoline demand in California**

*c. Vehicles, Infrastructure, and Barriers*

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

*2. Diesel*

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

*a. Historic consumption*

The table below shows California diesel consumption from 2006 to 2010, the latest year that data are available. The data are from CEC and BOE analyses. Diesel consumption saw a slight decrease in 2008, comparable to that seen in gasoline

consumption. Though diesel use has increased slightly from 2009 to 2010, the overall consumption of diesel has not fluctuated significantly since the publication of the 2009 staff report.

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

**Table IV-X:** Diesel fuel consumption in California 2006-2010

*b. Future demand*

The table below shows projected California diesel consumption based on the Low and High Petroleum Demand cases from the CEC’s 2009 IEPR. The high petroleum demand case represents primarily faster economic recovery and low crude prices. The low petroleum demand case represents primarily increases in fuel efficiency and lower alternative fuel prices. Projected increases in goods movement and increased use of diesel engines in general, lead to an outlook of increasing diesel demand. This trend is likely to be complimented by current and future fuel economy policies, since diesel vehicles are more fuel efficient than their gasoline counterparts.

Year	Diesel Low (Million Gallons)	Diesel High (Million Gallons)
2011	3,320	3,350
2012	3,420	3,460
2013	3,540	3,590
2014	3,630	3,690
2015	3,760	3,830
2016	3,780	3,850
2017	3,890	3,980
2018	4,010	4,120
2019	4,120	4,240
2020	4,230	4,350

**Table IV-X:** Projected diesel demand in California

*c. Vehicles, Infrastructure, and Barriers*

The number of diesel vehicles in California has been increasing; in 2008 there were nearly 600,000 **[CEC suggests 1,000,000, will follow up]**. About 80 percent of these vehicles were commercial vehicles, with another 15 percent being government vehicles and five percent for personal use **[CEC split, 83% commercial, 9% personal, 8% government, will follow up]**. The distribution infrastructure for diesel is mature,

although the number of dispensing facilities that offer diesel is likely to increase with the expected increase in diesel use for personal vehicles.

3. *Fuel Ethanol*

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

Since the original staff report was published in 2009, some facilities producing corn ethanol have increased their overall energy efficiency. These plants incorporate modern plant design developed by ICM and other firms, which results in less energy use in the plant. The reduction in energy use is derived from incremental improvements in multiple portions of the facility, including increases in ethanol yield, lower electricity use, installation of combined heat and power (CHP), lower temperatures for fermentation, more efficient enzymes, and more efficient natural gas boilers and other process equipment. In some cases the reduction in carbon intensity (CI) can be attributed to use of low carbon intensity inputs, such as biogas rather than CNG-natural gas powered equipment. Many of the facilities utilizing these technologies have been applying for custom CI values through the Method 2A/2B process.<sup>1</sup> These facilities have submitted applications over 100 additional pathways with CI values as low as 73.2 gCO<sub>2</sub>e/MJ.

a. *Historic consumption*

The volume of fuel ethanol consumed in California has been on a rising trend over the last few years. This is because of the blend volume of ethanol being set to 10 percent and the volume mandate set by the federal RFS2. Currently the volume of ethanol consumed is hovering around the blend limit of 10 percent of the gasoline volume. The table below shows California fuel ethanol consumption from 2006 to 2010, the latest year that data are available. The data are from CEC and DOE analysis.

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

**Table IV-X:** Ethanol Consumption in California 2006-2010

b. *Future Consumption*

<sup>1</sup> For more information see: <http://www.arb.ca.gov/fuels/lcfs/2a2b/2a-2b-apps.htm>

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The amount of fuel ethanol to be consumed in California will be highly dependent on overcoming the hurdles of additional E85 compatible vehicles, or increasing the E10 blend limit or both. In general the expectation is that due to policy directives such as the LCFS and RFS2, as well as subsidies, ethanol consumption in the State is expected to increase.

The table below shows projected California fuel ethanol consumption based on the Low and High Petroleum Demand cases from the CEC's 2009 IEPR. The high petroleum demand case represents primarily faster economic recovery and low crude prices. The low petroleum demand case represents primarily increases in fuel efficiency and lower alternative fuel prices.

Year	Ethanol Low (Million Gallons)	Ethanol High (Million Gallons)
2011	1,480	1,530
2012	1,510	1,560
2013	1,630	1,640
2014	1,820	1,810
2015	2,050	2,020
2016	2,210	2,160
2017	2,350	2,280
2018	2,510	2,410
2019	2,650	2,520
2020	2,780	2,640

**Table IV-X: Projected fuel ethanol demand in California**

*c. Vehicles, Infrastructure, and Barriers*

The state of ethanol distribution and blending infrastructure in the state is mature, with most terminals having dedicated tankage and facilities to accommodate ethanol.

There are several remaining barriers that remain in the way of further ethanol penetration. Most cars today are not certified to run on blends of ethanol above 10 percent, which in addition to legal barriers will relegate ethanol use in California to E10 and E85 for the near future. Additionally, ethanol is not able to be pipelined in the current infrastructure, which means that transportation must remain by truck and train, which are less efficient than pipelines.

*d. Historic Consumption of E85*

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

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

**Table IV-X:** E85 Consumption in California 2006-2010

*e. Future demand of E85*

The demand for E85 is expected to grow. The growth in E85 use is related to the rate of growth in E85-compatible, flex fuel vehicles (FFVs). The table below shows the projected California E85 consumption based on the Low and High Petroleum Demand cases from the CEC’s 2009 Integrated Energy Policy Report. The high petroleum demand case represents primarily faster economic recovery and low crude prices. The low petroleum demand case represents primarily increases in fuel efficiency and lower alternative fuel prices.

Year	E85 Low (Million Gallons)	E85 High (Million Gallons)
2011	1.6	1.6
2012	1.9	2.0
2013	107	35.5
2014	322	219
2015	632	503
2016	858	693
2017	1,080	878
2018	1,310	1,080
2019	1,520	1,250
2020	1,720	1,440

**Table IV-X:** Projected future demand for E85

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

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

RFS2 requires fuel producers to use progressively increasing amounts of biofuels, culminating in at least 36 billion gallons of biofuel by 2022. Using the volumes requirements, ARB staff estimated the number of FFVs that will be needed under RFS2. To determine the estimated number of FFVs, staff used 23.3 mpg for the average fuel economy for E10 gasoline and 17.4 mpg for E85 in the analyses for 2020. Staff used

the same energy requirement to propel the vehicles (4.97 MJ/mi) for E10 and E85. The FFV population for RFS2 is listed in Table 2 for both 100 percent refueling with E85 and 75 percent refueling with E85.

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

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

As a lower bound estimate, the estimated projection for FFV is based on already known commitments from automobile manufacturers, including commitments from GM, Ford and Chrysler in doing 50 percent FFVs beginning in 2012. The table below illustrates the lower and upper bounds of the projected FFV population. Based on the calculations, there will be an ample number of FFVs available to consume E85 volumes that may play a role in meeting the LCFS.

*[GATHERING 2011 DATA]*

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

**Table IV-X:** Projected FFV population

4. *Cellulosic Ethanol*

Ethanol derived from cellulosic material is on the horizon. The most researched pathway to produce cellulosic ethanol from biomass is through hydrolysis and fermentation. This process is similar to production of ethanol from grains, except that it is significantly more difficult to hydrolyze cellulose than starch. An alternative pathway involves gasification of cellulosic biomass to produce syngas. The syngas can be converted to ethanol using a modified Fischer-Tropsch synthesis or by fermentation

<sup>2</sup> Evaluation is still being conducted for 2011.

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techniques. More background on types of technologies can be found in Chapter III of the LCFS staff report.

The commercial production of cellulosic ethanol has not met the expectations contained in RFS2 mandates. U.S. EPA can respond to market conditions and revise RFS2 volumes. For example, U. S. EPA reduced the 2011 mandated volume of cellulosic ethanol for the RFS2 from 250 million gallons to six million gallons. EIA suggests that a more likely 2011 production total for cellulosic biofuels is approximately four million gallons. U.S. DOE is still processing grants to help stimulate cellulosic biofuels.

### *a. Historic Consumption*

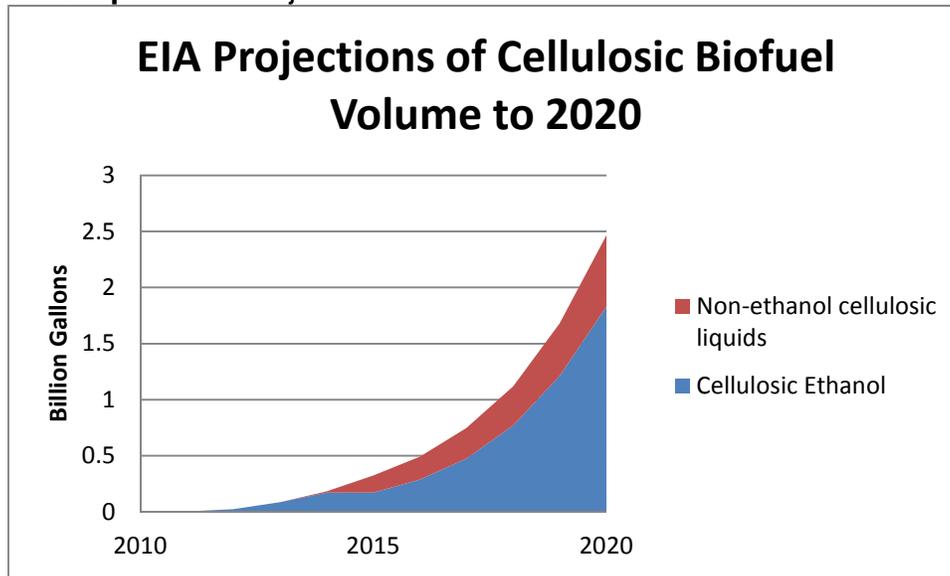
The prior consumption of cellulosic ethanol is essentially insignificant, and on the order the low millions of gallons for the entire U.S. Likely very little of that volume was consumed in California.

### *b. Future Consumption*

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

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

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

**Graph IV-X:** Projected cellulosic biofuel volume 2010 to 2020

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

Year	RFS2 Cellulosic Biofuel Standard Volume Requirements <sup>3</sup> (Billion Gallons)	EIA cellulosic ethanol projections (Billion Gallons)	California's Proportional "Share" of Cellulosic Biofuel (Billion Gallons)
2010	0.10	0.00	0.00
2011	0.25	0.00	0.00
2012	0.50	0.02	0.002
2013	1.00	0.09	0.010
2014	1.75	0.18	0.020
2015	3.00	0.32	0.036
2016	4.25	0.49	0.055
2017	5.50	0.75	0.085
2018	7.00	1.12	0.127
2019	8.50	1.68	0.190
2020	10.50	2.47	0.279

**Table IV-X:** Cellulosic Ethanol Projections for 2010 - 2020

*c. Vehicles, Infrastructure, and Barriers*

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

*5. Natural gas*

While there have not been technological advances in the infrastructure for delivery, natural gas use in the transportation sector—both as compressed natural gas (CNG) and liquefied natural gas (LNG)—has increased over the last few years. Table 1 below shows the consumption of natural gas as transportation fuel in California from 2006 to 2009. The consumption has increased at an average rate of nine percent per year. This increase could be attributed to potential fuel cost savings from natural gas relative to traditional fossil fuels, such as gasoline and diesel. On an energy-equivalent basis, natural gas fuel is less expensive than gasoline or diesel. If these fuel savings are maintained, natural gas use should continue to increase. The use of natural gas provides additional benefits besides economic, such as emission reductions for greenhouse gases, criteria pollutants, and toxics.

*a. Historic consumption*

California vehicular natural gas consumption has been increasing. The table below shows California vehicular natural gas consumption from 2006 to 2010, the latest year that data are available. The data are from the U.S. Energy Information Administration

<sup>3</sup> Original RFS2 projections used in the 2009 U.S. EPA staff report.

(U.S. EIA). As can be seen in the table, natural gas use has increased by about 50 percent over this period, from approximately 9,900 million standard cubic feet (mmscf) or 84 million gallons gasoline equivalent (millions GGE) in 2006 to 14,800 mmscf or 117 million GGE in 2010.

Year	Natural Gas, as CNG or LNG	
	(mmscf)	(million GGE) <sup>4</sup>
2006	9,889	84
2007	11,015	93
2008	11,705	99
2009	13,132	111
2010	14,798	125

**Table IV-X:** Vehicular natural gas consumption in California, 2006-2010

*b. Future demand*

California vehicular natural gas consumption is projected to increase. This increase is directly tied to greater penetration of new vehicles compatible with natural gas or vehicles converted to use natural gas, as well as installation of additional natural gas refueling infrastructure.

*c. Vehicles, Infrastructure, and Barriers*

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

Year	LDVs	HDVs <sup>5</sup>	Total
2006	24,900	7,900	32,800
2007	25,200	8,600	33,800
2008	24,800	9,700	34,500
2009	24,800	11,300	36,100
2010 <sup>6</sup>	24,800	12,900	37,700

**Table IV-X:** Natural Gas Vehicles in California, 2006-2010

<sup>4</sup> 118 scf of natural gas ~ 1 GGE (1 scf of natural gas = 930 Btu; 1 gallon of CA gasoline = 109,800 Btu)

<sup>5</sup> Includes small number of MDVs.

<sup>6</sup> Extrapolated from 2008-2009 numbers

## 6. *Biogas*

It has been projected that biogas generation could expand based upon the current sources of biomass and agricultural waste products. EPA's joint program, AgSTAR, projects that the number of anaerobic digesters could increase by at least tenfold.<sup>7</sup> Various studies by CEC and other California agencies suggest that biogas could displace diesel use (in California) by a few billion gallons depending on biomass allocation and technological availability.

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

There are several barriers to bringing California biogas to market, including: the low cost of fossil natural gas; pipeline natural gas toxicity issues such as prohibition of landfill gas transportation; pipeline safety standards; economic issues of linking output from small agricultural processing facilities and farms into a central processing facility; the cost of building a pipeline interconnect at each biomethane production facility; and incentives encouraging conversion to electrical production over direct pipeline injection. Permitting requirements in California can be more time-intensive and require an increase in capital investments due to their thorough nature; this may cause hesitation when constructing a biomethane gas processing and distribution station.

Currently, a multimillion dollar investment is required to build an interconnect between an RNG source and the public utility pipelines. RNG producers have suggested that implementing standardized interconnect designs or a rate-based developer cost associated with each interconnect would increase the feasibility of additional sources. AgSTAR currently identifies about a dozen active anaerobic digester sites in California, however a majority of these are currently converting their biogas to electricity.<sup>8</sup> While there is a possibility for additional expansion throughout the nation, sites that would be economically feasible for individual interconnects would be limited at this time without an additional influx of funding.

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<sup>7</sup> Agricultural Biogas in the United States, Bramley et al., Tufts University Urban & Environmental Policy & Planning, May 2011,

[http://ase.tufts.edu/uep/Degrees/field\\_project\\_reports/2011/Team\\_6\\_Final\\_Report.pdf](http://ase.tufts.edu/uep/Degrees/field_project_reports/2011/Team_6_Final_Report.pdf)

<sup>8</sup> U.S. Anaerobic Digester Status Report, US EPA, October 2010,

[http://www.epa.gov/agstar/documents/digester\\_status\\_report2010.pdf](http://www.epa.gov/agstar/documents/digester_status_report2010.pdf)

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In current situations where interconnects are not feasible, the fuel requires additional processing before transport. The costs associated with this endeavor require gas to be liquefied (compression and chilling costs) and then transported to another location for fueling. Biomethane gas is rarely produced in the same location in which it will be used that is effective for fueling a fleet; notable exceptions may be landfill and dairy equipment. In instances where interconnects are feasible, there are still pipeline quality standards that need to be met before the gas can enter the pipeline. These standards are defined in tariffs agreed upon by the pipeline companies and public utilities and therefore depending on the location of injection may limit the ability to market the fuel.

The current federal tax credits create an incentive for the production of self-generated electricity on site when biomethane is produced. Self-generated electricity tends to be less efficient and may cause more emissions than if the gas were injected into the pipeline where central stations would convert the natural gas into electricity. If the same incentives were applied to both electrical generation and injection of clean and safe renewable gas into the pipeline, the ability to market the gas more broadly would generate greater market activity. Note that the production of electricity from RNG sources is becoming more difficult in non-attainment air districts. Basins such as the South Coast Air Basin have stringent limits on criteria pollutants such as particulate matter and NOx in an effort to make progress towards attaining healthy air quality.

Overall capital investors need more assurances that the market will be stable to properly plan and allocate funding or incentives. Investors seek certainty to avoid poor investment decisions in the future; these uncertainties may be the result of a new barrier being established or additional incentives, which are directed towards competing fuels or technologies.

### *a. Historic consumption*

To date there has been no significant use of biogas to power vehicles. However there have been limited projects, such as the use of landfill gas to power LNG refuse trucks.

### *b. Future demand*

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

### *c. Vehicles, Infrastructure, and Barriers*

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

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There are several barriers to bringing biogas to market, including: the low cost of fossil natural gas; the prohibition of injecting landfill gas into natural gas pipelines because of concerns about vinyl chloride contamination; the cost of building an interconnect at each biomethane production facility; and the economic advantages in many cases of using biogas for electricity generation due to less fuel clean-up requirements. Permitting requirements in California can be more time-intensive and require an increase in capital investments due to their thorough nature; this may cause hesitation when constructing a biomethane gas processing and distribution station.

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

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

The current federal tax credits incent the production of electricity on site when biomethane is produced, but this can be inefficient and may cause more emissions than if the gas were injected into the pipeline where a major natural gas electric power generation unit was converting the energy. If the same incentives were applied to both electrical generation and injection of renewable gas to the pipeline, the ability to sell to more than one buyer would generate additional security in the market. Note that the production of electricity from RNG sources is becoming more difficult in non-attainment air districts. Basins such as the South Coast Air Basin have stringent limits on criteria pollutants, such as particulate matter and NO<sub>x</sub>, in an effort to make progress towards attaining ambient air quality standards.

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

### 7. *Biodiesel*

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Biodiesel is defined as a fatty acid methyl ester derived from vegetable oils or other renewable feedstocks. Biodiesel is commercially available, supplying about five million gallons of fuel in California in 2010, and about 350 million gallons of fuel in the U.S.

The primary feedstocks available for biodiesel production in California are waste vegetable oil, animal fats, inedible corn oil, and soybean oil. Of these feedstocks, waste vegetable oil, animal fats, and inedible corn oil are waste feedstocks and result in biodiesel of very low carbon intensity. The majority biodiesel production facilities in California are designed primarily to use these waste feedstocks.

According to the LCFS staff report in 2009, California biodiesel production facilities had a combined nameplate capacity of about 35 million gallons. Staff's update conducted for this review has determined that nameplate capacity has doubled—to about 70 million gallons—as of 2011.

*a. Historic consumption*

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

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

**Table V-6:** Biodiesel consumption in California 2006-2010

There are several factors that have likely played a part in the decrease in biodiesel consumption including the downturn in the economy: implementation of Water Resource Control Board rules for Underground Storage Tanks, ASTM adoption of a B6-B20 quality specification, and the expiration of the federal blender's tax credit in 2010.

*b. Future demand*

The LCFS and RFS2 are expected to drive additional demand for biodiesel in California. The table below shows the projected consumption of biodiesel in California based on the Low and High Petroleum Demand cases from the CEC's 2009 Integrated Energy Policy Report. The high petroleum demand case represents primarily faster economic recovery and low crude prices. The low petroleum demand case represents primarily increases in fuel efficiency and lower alternative fuel prices

Year	Biodiesel Low (Million Gallons)	Biodiesel High (Million Gallons)
2011	48.9	47.3
2012	61.0	58.4
2013	62.0	59.3
2014	63.2	60.3
2015	65.2	61.9
2016	64.5	61.4
2017	65.8	63.1
2018	67.0	64.7
2019	68.0	66.2
2020	68.7	67.9

**Table IV-X:** Projected future demand for Biodiesel in California

*c. Vehicles, Infrastructure, and Barriers*

Current diesel powered vehicles are capable of using biodiesel blends up to 20 percent without major modification, depending on climate and other factors. However, many diesel engine manufacturers only recommend using biodiesel blends up to five percent, which may affect the warranties of some vehicles and therefore prohibit use of biodiesel blends above five percent.

*8. Renewable diesel*

Hydrogenation Derived Renewable Diesel (HDRD) is a liquid hydrocarbon fuel with very similar chemical properties to petroleum diesel. HDRD is derived from the same triglyceride feedstocks as biodiesel; vegetable oils and animal fats. HDRD is similar to renewable diesel derived from other feedstocks and production technologies, such as enzyme produced renewable diesel and pyrolysis oil derived renewable diesel, however HDRD is a current technology and is produced using a distinctly different process than these other future technologies.

In addition to producing HDRD as a standalone product, some refineries may be capable of co-processing triglyceride feedstocks and petroleum feedstocks, resulting in a diesel product that is partially derived from renewable sources. This co-processed diesel may be produced by inserting the triglyceride feedstock into the refinery stream prior to the refineries hydro-treating unit resulting in n-paraffins with carbon chain lengths between 12 and 24 as well as propane, water, and CO<sub>2</sub> by-products.

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

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### *a. Historic consumption*

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

### *b. Future demand*

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

### *c. Vehicles, Infrastructure, and Barriers*

Renewable diesel is generally similar enough to petroleum diesel that all current vehicles should be able to use it without engine modification. However, currently engine manufacturers do not explicitly include renewable diesel as an recommended fuel, so there is some question as to whether warranties will be honored with the use of renewable diesel. The chemical composition of renewable diesel is within the range of the products currently being distributed by the current petroleum infrastructure, so there should be no changes needed to that infrastructure to accommodate renewable diesel.

## *9. Electricity*

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

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

As the annual CI standards tighten throughout the decade, the amount of credits earned by EVs diminishes because of the smaller difference between the CI of electricity and the CI of the lower standard. For example, in 2020, when the CI standard is 10 percent lower than 2010, staff estimates that battery electric vehicles would earn approximately 1.7 credits per vehicle, while plug-in hybrids would earn 1.3 credits per vehicle. The

number of credits projected for the year 2020 varies considerably based on the projected number of electric vehicles. Based on these scenarios, LCFS credits available in 2020 could be 700,000 to 2,500,000 MTCO<sub>2</sub>e. Compared to the total reduction of CO<sub>2</sub>e in 2020, credits could be 3 to 10 percent of the total reduction. The potential value of the credits based on a range of \$15 to \$50 per credit, could range from \$10 to \$124 million.

a. *Historic consumption*

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

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

**Table IV-X:** Vehicular electricity consumption in California 2007-2010

b. *Future demand*

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

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

**Table IV-X:** Projected future demand for vehicular electricity in California

c. *Vehicles, Infrastructure, and Barriers*

Staff estimates that in 2011, there will be 5,000 to 11,000 electric vehicles operating in California. This includes full-electric vehicles like the Nissan Leaf and Tesla Roadster,

and plug-in hybrids like the Chevy Volt. Based on typical annual miles traveled using electricity supplied from the California grid, a battery-electric vehicle could earn about two credits in 2011, while a plug-in hybrid could earn one-and-a-half credits in 2011 (one credit is equal to one MTCO<sub>2e</sub>). LCFS illustrative scenarios were based on 490,000 to 1,780,000 electric vehicles (both battery and plug-in hybrid) in 2020.

#### 10. *Hydrogen*

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

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

#### 11. *Butanol*

As a renewable fuel, butanol has a number of advantages over ethanol. Butanol has higher energy density than ethanol, can be mixed with gasoline in more flexible proportions than ethanol, and is less corrosive, less volatile, and less water soluble than ethanol. As a result, butanol can be transported through existing fuel pipelines. However, the incomplete combustion of butanol can result in small amounts of butyric acid, which has a strong odor. Biobutanol is produced by fermentation of sugar using either genetically modified organisms or carefully selected, naturally occurring micro-organisms. On the horizon is the possibility of producing biobutanol using lignocellulosic material in a way similar to lignocellulosic ethanol production.

Currently biobutanol is not available in commercial quantities. Three companies are currently pursuing biobutanol production in the U.S.: Butamax (a joint venture of BP and DuPont), Cobalt biofuels, and Gevo.

#### 12. *Algal biofuels*

Algae are generally considered a very attractive potential feedstock for fuel because of the possibility of relatively high yields compared to conventional crops. There are generally two methods of producing fuel from algae that are currently being explored. The first method is to modify the algae such that it grows as much biomass as quickly as possible and then to process the algae biomass in a gasification facility. The second method is to modify the algae to produce as much oil as possible and then to harvest the oil either by skimming of secreted oil or by destruction of the algae followed by

collection. Both of these processes are still in the research and development stage of production.

Some estimates place algae's potential yield as high as 6,500 gallons of biofuel per acre, compared to about 600 gallons per acre for the most productive conventional crops. Additionally co-placement with high CO<sub>2</sub> emitting facilities holds promise due to the potential of algae to sequester the CO<sub>2</sub> emissions during growth. However, there are no commercial scale facilities producing algae.

## *B. Investment*

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

### *1. Funding for Advanced Biofuels*

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

The Cleantech Group forecasts the market of low-carbon fuels at \$33.4 billion by 2020. This is nearly double the future market of energy efficiency (\$17.3 billion), and significantly higher than renewable electricity (\$20 billion)<sup>9</sup>. To seize this opportunity, venture capitalists have invested at least \$1.76 billion in active North American companies from 2007 through the first quarter of 2011, according to publicly available data.

### *2. Policies, programs & tax incentives for advanced biofuels*

#### *a. DOE Guarantees*

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

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<sup>9</sup> Cheng, David, "California in Perspective: An Overview of State Energy Policies." Cleantech Group, 2010.

*b. AB 118*

Assembly Bill 118 authorizes the Energy Commission to spend about \$100 million per year for over seven years to “develop and deploy innovative technologies that transform California’s fuel and vehicle types to help attain the state’s climate change policies.” The statute, amended by AB 109 (Nunez, 2008), directs the CEC to create an advisory committee to help develop and adopt an Investment Plan for the program. The Investment Plan is intended to determine program priorities and opportunities, and describe how funding will complement existing public and private investments, including existing state and federal programs. The ARB is represented on the advisory committee. Funds are awarded through the CEC process beginning with a Grant Solicitation for specific category, all proposals are then ranked by adherence to technical criteria, and those receiving priority rankings are funded.

Mid-way into the second funding cycle of the Alternative and Renewable Fuel and Vehicle Technology Program, investment plans have guided the awarding of monies to six fuel categories. A total of \$174 dollars have been awarded to date.

- \$42.5 million for electric (charging infrastructure, medium- and heavy-duty advance vehicle demonstrations, manufacturing facilities and equipment)
- \$15.7 for hydrogen (fueling stations)
- \$5.7 million for natural gas (fueling infrastructure)
- \$35.3 for biomethane (production)
- \$10.5 million for ethanol (E-85 fueling stations, production incentive program, fuel production)
- \$8.2 million for biodiesel (upstream fueling infrastructure, and fuel production)

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

- \$39 million for vouchers for California businesses to buy lower-emitting and fuel-efficient hybrid and zero-emission trucks and buses through the Hybrid Truck and Bus Voucher Incentive Project (HVIP). About 900 vehicles have been funded to date, and the Energy Commission has augmented the project with \$4 million of its AB 118 funding to help meet demand.
- \$9 million for consumer rebates toward the purchase of light-duty zero-emission or plug-in hybrid passenger vehicles through the Clean Vehicle Rebate Project (CVRP). About 2,000 vehicles have been funded to date, and the Energy Commission has augmented the project with \$2 million of its AB 118 funding to help meet demand.
- \$4 million for technologically promising demonstration projects needed for California to meet its longer-term air quality goals. Ten projects are in progress

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demonstrating advanced emission controls on locomotives, marine engines, and commercial lawn and garden equipment.

- \$2.6 million to expand air district program which provide rebates to consumers who scrap old gasoline powered lawn mowers and replace them with zero-emission models. Over 12,000 lawn mowers have been replaced to date.
- \$2 million for an off-road hybrid construction equipment demonstration project
- \$1.1 million for a zero-emission agricultural utility terrain vehicle rebate project

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

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

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

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

### c. *VEETC*

Due to the current state of flux and uncertainty surrounding the future of the Volumetric Excise Ethanol Tax Credit (VEETC), this section will be expanded prior to the final draft.

### C. *Ultralow-carbon fuels*

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

Currently, the LCFS does not contain any special provisions for the use of ultralow carbon fuels; these are treated like all other fuels subject to the LCFS (i.e. they are given a CI commensurate with their lifecycle GHG emissions). The concept of incenting the use of ultralow carbon fuels, with provisions specific to these fuels, was discussed during the development of regulation. However, such fuel-specific incentives ultimately were not included because the Board, as well as a fair portion of stakeholders, believed

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at the time of the hearing that the LCFS should remain fuel-neutral. It was thought at the time that the inclusion of provisions for ultralow carbon fuels would create “winners and losers” within the program and make the LCFS less driven by market forces and performance and more driven by incentives and mandates. Additionally, incentives such as credit multipliers, presumably would impact the real-world reductions that would otherwise be achieved under the program.

With that being said, the LCFS relies on the development of ultralow carbon fuels in order to meet the 2020 goals, and we will undoubtedly need them to meet any State targets set for post-2020. The fuels generally have very low CIs. Thus, they have the potential to generate credits under the LCFS. In recognition of this, the LCFS regulation (section 95489(a)(5)) directs the Executive Officer, as part of the program reviews, to consider the advisability of establishing additional mechanisms to incent higher volumes of these fuels to be used.

If we are not seeing the development of these fuels in sufficient volumes based solely on the need for regulated parties to comply with the LCFS, special provisions within the regulation may aid in their development and ought to be discussed. However, because the LCFS is still in the infancy of its implementation, it is premature to determine how companies will comply with the more stringent goals of the later years of the program. If their main choice of compliance is banking credits in the earlier years when the regulation goals are less stringent, perhaps the LCFS may need to consider provisions to further encourage the development of ultralow-carbon fuels.

However, as indicated above, we believe it is premature to recommend such adjustments given that the program is in its early stages but are interested in stakeholder perspectives on the issue. But, it is important to note that any recommended adjustments would need to be informed by technical analysis and full vetting through a stakeholder process.

### *D. Impact on State fuel supplies*

#### *1. RFS2*

Congress adopted the Energy Independence and Security Act of 2007 (EISA) in December 2007, which required EPA to institute a second, and stronger, Renewable Fuels Standard (RFS2). In 2010, the EPA promulgated the RFS2 regulation which requires that 16 billion gallons of advanced biofuels and 36 total gallons of biofuels be produced in the U.S. by 2022.

The RFS2 provisions are complimentary to the LCFS in that the technology required to produce the amounts of fuel required by the LCFS are the same technology required to produce the RFS2 fuels. Implementation of both of these regulations should lead to a more diverse fuel pool in California. Although the RFS2 regulation is meant to be technology forcing, the EPA so far has been revising the requirements to be more in line with the current state of technology, so the RFS2 may not have as effective in driving

investment as initially perceived. As such, the RFS2 impact on the State fuel supplies may not be transformative in and of itself.

2. *LCFS*

a. *LCFS requirements effect on fuel pool*

Because the LCFS does not require specific volumes of any one fuel, it may be difficult to accurately predict the impact it will have on State fuel supplies. However, the LCFS will almost certainly increase the amount of alternative fuels that are consumed in the State, including: ethanol, natural gas, biodiesel, renewable diesel, electricity, and hydrogen.

The quantitative mix of fuels will be determined significantly by the RFS2 requirements, and beyond that the feedstock carbon intensity, combined with the production economics should determine the remainder. For example, if a fuel has a very low carbon intensity and is derived from low production cost feedstocks, that fuel will likely contribute significantly to the non-RFS2 amount of fuel in the State. Conversely if a fuel has either a high carbon intensity or is derived from high production cost feedstocks, that fuel is unlikely to contribute significantly to the non- RFS2 amount of fuel in the State.

b. *Supply and demand*

A pertinent question is whether the effect of the LCFS on State fuel supplies will impact the ability of the fuels market to satisfy demand. The answer to this question lies primarily in the future development of alternative fuels from an economic and technology advancement perspective. These advances are derivative of factors including: government policies at the national and state level, investment, and diminishing resources.

In order for the fuels market to meet the projected demand for transportation fuels, two things must happen. First, the current state of technology and the ability to produce fuels from difficult feedstocks, such as cellulosic feedstocks, animal and human waste products, and solar radiation, must advance in order to increase commercial ability to supply these fuels. Second, the economics of these production processes must develop such that they can meet demand at prices competitive to conventional fuels. Both of these advancements will be influenced by multiple factors.

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

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

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

### 3. *Blend limits*

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

Currently ethanol blend limits are either at or below 10 percent by volume or E85 for use in FFVs. In order to change this, a rulemaking must be undertaken to increase the limit beyond 10 percent. The U.S. EPA recently waived the E10 limit for certain newer vehicles, approving an E15 blend, but the emergence of E15 in California as a transportation fuel will take several years of testing and rule development should the State decide to move in that direction.

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

#### E. *Future monitoring*

##### 1. *LRT*

The LCFS Reporting Tool (LRT) is an online system that enables regulated parties to report quarterly and annually to meet their LCFS reporting obligations. It is designed to

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store data associated with the quantities of transportation fuels reported and to calculate the LCFS credits and deficits generated for each regulated party. The credit calculation is based on the carbon intensity (CI) of the fuels reported and the compliance obligation associated with the type of fuel transaction (production, import, purchase, etc.). As of July 2011, there are over 70 LCFS parties registered in the LRT. The total number of fuel transactions has surpassed 160,000 for three quarters of reporting (Q3, Q4 2010, and Q1 2011) and expected to grow per quarter as additional regulated parties register in the LRT. The LRT will have over 100 transportation fuel entities long-term and the number of reporting regulated parties is expected to have a five to ten percent growth rate during the initial compliance years as additional fuel entities “opt-in.”

Quarterly LCFS reporting in the LRT enables ARB to track conventional and alternative fuels produced, imported, purchased and sold under the LCFS Program. The LRT is designed to capture and store LCFS data on a quarterly basis, which will be converted into a variety of informational reports. These reports will include trends, as well as credit availability and trading activity. Trend reports will eventually be available on a regular basis for all reported fuels, with potential upgrades to the LRT increasing the informational content as well as inclusion of credit market reports. Additional information will also be accessible because of the tight integration of the Biofuel Producer/Facility Registration and the LCFS Method 2A/2B Application Process with the upgraded LRT. Additional data from these two processes will also assist ARB in more accurately projecting transportation fuel outlooks for the future in California.

## 2. CEC

The California Energy Commission is the regulatory agency responsible for determining whether California has enough resources to provide the energy needs of the State on a continuing basis. One of the major tools they employ for to meet this goal is a biannual Integrated Energy Policy Report, in which they examine the available energy supplies and identify areas where supplies are deficient. ARB will be keeping up with this process and using it as a tool to help determine what impact the LCFS is having on State transportation fuel supplies.