The following document is the first rough draft of the technology assessment chapter that will be incorporated into the final review report that is due to the Board in December. There are several sections that are still under review by ARB staff along with 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.

This document has been developed using the workplan as guidance, though for the sake of grouping similar topics together, covers several areas called out in the regulation. This chapter specifically tries to answer the questions related to technology advances since the last staff report, the concept of ultralow carbon fuel provisions, the advisability of including provisions for those fuels, and possible ways to incentivize those fuels. Volumes and projections will be covered in the chapter pertaining to "Supply and Impact on State Fuel Supply."

IV. Technology Assessment

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. Integral to this section are topic 4 (advances in production), topic 5 (ultralow carbon fuels), and topic 11 (hurdles and barriers). Thus, elements from each of these topics have been integrated into this chapter.

A. Advances in Technology

1. Current technologies

a. Gasoline and Diesel

[Will include a discussion of refinery types in California.]

b. Ethanol derived from grains and sugars

Since the original staff report was published in 2009, facilities producing ethanol from corn have been increasing the efficiency of their facilities. These plants incorporate modern plant design developed by ICM, 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, and more efficient 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-powered equipment. Facilities utilizing these technologies have been applying for custom CI values through the Method 2A/2B process[1]. Table XX lists the plants that have CI values approved that are below the published value for Midwest corn ethanol produced in a similar fashion.

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

[Table XX. INSERT TABLE OF NEW CI VALUES]

c. Biodiesel derived from crops and waste fats and oils

Biodiesel is defined as a fatty acid methyl ester derived from vegetable oils or other renewable feedstocks. Biodiesel is a currently commercially available fuel, supplying in 2010 about 5 million gallons of fuel in California, 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, California biodiesel production facilities have a combined nameplate capacity of about 35 million gallons. Analysis conducted during this review estimates that there are facilities with about 70 million gallons of nameplate production capacity in California as of 2011.

Chris Malins 7/14/11 6:54 PM
Comment [1]: In the UK in particular, the indirect consequences of using animal fat for biodiesel have been explored in some detail. In the UK market, it has been concluded that the net systemic carbon benefits of using animal fat for biodiesel are likely to be limited, as it has a variety of existing carbon efficient uses. I suggest that the language about 'wastes' should reflect the possibility that diverting 'waste' streams form existing uses may cause carbon emissions elsewhere. http://www.renewablefuelsagency.org/_db/_documents/RFA-DECC_Indirect_Effects_of_Wastes_Report.pdf

Chris Malins 7/14/11 6:56 PM
Comment [2]: It would be useful to have some indication one way or another of whether significant efficiency savings or process amendments (e.g. utilizing renewable methanol) are likely to be available in the coming years for biodiesel

f. 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. Various studies by CEC and other California agencies suggest that biogas could displace diesel use by a few billion gallons depending on biomass allocation and technological availability.

Most renewable natural gas is being produced outside the state and transported into California for use. Current methods utilize truck or rail lines to carry the renewable natural gas (RNG) to the state, but depending on the distance and volumes, the method is quite costly. Transport of RNG into the state through pipelines would reduce those costs; the estimated transportation costs project to be $0.75 to $2.50/ MMBtu. Projects within the state that are utilizing biomethane 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 GPD 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 biogas to market, including: the low cost of fossil natural gas; the strict limits on landfill gas because of vinyl chloride contamination; other pipeline standards restricting entry; the cost of building an interconnect at each biomethane production facility and disincentives towards gas production while incentivizing 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 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 incentivize the production of electricity on site when biomethane is produced, but this is highly 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 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.

f. Natural Gas

While there have not been technological advances in the production of natural gas or 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 between 2006 - 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, the economic driving force for natural gas use should continue to increase.

Table 1
Natural Gas Consumption in California, 2006-2009

Year	Transportation Fuel (CNG &LNG) (Million Cubic Feet)
2006	9,900
2007	11,000
2008	11,700
2009	13,100

Source: U.S. Energy Information Administration

The use of natural gas provides additional benefits besides economic, such as emission reductions for greenhouse gases, criteria pollutants, and toxics. Another factor that has been an important role for increased fuel consumption was the expansion of the natural gas vehicle (NGV) population. These NGVs can be categorized into two vehicle classes: light duty vehicles (LDVs) and heavy-duty vehicles (HDVs). Table 2 displays the NGV population from 2006 - 2009, these values have been estimated from the California Department of Motor Vehicles' (DMV) database.

Table 2
Natural Gas Vehicles in California, 2006-2009

Year	LDVs	HDVs	Total
2006	15,490	7,650	23,140
2007	14,510	8,330	22,840
2008	14,770	9,830	24,600
2009	15,220	11,150	26,370

Source: California DMV

During this four-year span, the population of HDVs has increased by more than 45 percent, while the population of LDVs has slightly decreased. Implementation of fleet rules and the available financial incentives have assisted the growth of HDVs. Although LDVs still outnumber HDVs (school and transit buses, line-haul and refuse trucks), the majority of natural gas is consumed by HDVs. Generally, HDVs will travel greater distances and consume more fuel based upon their heavier loads and powerful duty cycles.

h. 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.

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 $MTCO_2e$). The projected total number of credits available in 2011 for the electricity-fueled miles traveled by these vehicles is 8,000 to 22,000 $MTCO_2e$. The potential value of the credits for all electric vehicles statewide in 2011, based on a range of $15 to $50 per credit, could range from $114,000 to $1,100,000.

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. LCFS illustrative scenarios were based on 490,000 to 1,780,000 electric vehicles (both battery and plug-in hybrid) in 2020. Based on these scenarios, LCFS credits available in 2020 could be 700,000 to 2,500,000 $MTCO_2e$. Compared to the total reduction of CO_2e in 2020, credits could be 3 to 10 percent of the total reduction. The potential value of the credits based on a range of $15 to $50 per credit, could range from $10 to $124 million.

h. Hydrogen

Currently, hydrogen stations are funded through ARB Hydrogen Highway (seven locations, 60-140 kg/day) and CEC AB 118 funding (eight locations, 100-240 kg/day). Hydrogen infrastructure challenges: Fuel Cell Vehicle (FCV) roll-out projections are based on infrastructure in-place ahead of vehicles; good station coverage is needed to boost consumer confidence in FCVs; early stations are costly; and government funding needed to offset capital and operations and maintenance (O&M) when demand is low.

2. Near-term future technologies

This section groups the fuels and conversion technologies expected to be available for commercial use in the 2015 timeframe. In addition to the fuels listed below, we expect that CNG, hydrogen, and electricity will play a larger role as the technologies become more robust and their availability increases.

a. *Ethanol derived from lignocellulosic biomass*

The traditional pathway to produce lignocellulosic ethanol from biomass is through hydrolysis and fermentation. This process is similar to production of ethanol from grains, except that it is significantly more difficult to hydrolyze lignocellulose than starch. An alternative pathway involves gasification of lignocellulosic biomass to produce syngas. The syngas can be converted to ethanol using a modified Fischer-Tropsch synthesis or by fermentation techniques. More background on types of technologies can be found in Chapter III of the staff report. More information on facilities and volumes can be found in Chapter 5 of this report. U.S. EPA reduced the cellulosic biofuels portion for the RFS2 from 250 million gallons to 6 million gallons for 2011. EIA suggests that a more likely 2011 production total for cellulosic biofuels is approximately 4 million gallons. U.S. DOE is still processing grants to help stimulate cellulosic biofuels.

Chris Malins 7/14/11 7:14 PM

Comment [3]: Given the non-ideal properties of ethanol as a fuel, wouldn't it be preferable to produce a drop-in gasoline replacement using the gasification route? If gasification to ethanol is an expected route I would find it helpful to have some explanation of why that seems most likely.

b. *Others*

[Will include additional fuels, updates to come]

3. Long-term future technologies

This section discusses the fuels and conversion technologies that are expected to be available on a commercial scale after 2020.

a. *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 CO2 emitting facilities holds promise due to the potential of algae to sequester the CO2 emissions during growth. However, there are no commercial scale facilities producing algae.

Chris Malins 7/14/11 7:20 PM

Comment [4]: This statement isn't very informative on its own – while there are indeed some very optimistic assessments of algal fuels, others are rather less so. It would be useful to explore in slightly more detail the barriers to commercialization of algae, and perhaps indicate the yield achieved to date in some demonstration projects as a more realistic indicator of medium term potential. I would be interested in whether the staff and panel have any reflections on the benefits of algal turf scrubber technology as an algal system with environmental co-benefits.

b. *Biobutanol*

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 organism 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.

Chris Malins 7/14/11 7:58 PM
Comment [5]: Are there any declared timescales to commercialization form these companies?

c. *Others*

[Seeking panelist input, will be updating]

B. Investments in Low Carbon Fuels [Bob Epstein, et al.]

1. Funding for Advanced Biofuels
   a. Venture and finance data – by quarter, series, category, region, company
      i. Strategic investments
      ii. Venture capital
2. DOE Guarantees
   a. Funds distributed in 2009-2010
   b. Funds distributed in 2010-2011
   c. Projected funds
3. Policies, programs & tax incentives utilized by advanced biofuels
   a. USDA Loan Guarantees
   b. AB 118
   c. VEETC
   d. Others (as provided by E2 workgroup)
4. Production data by company
   a. Market regions
   b. Fuel type
   c. Projected quantity

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 incentivizing the use of ultralow carbon fuels, with provisions specific to these fuels, was discussed during the development of regulation. However, such fuel-specific incentives ultimately were not included because the Board, as well as a fair portion of stakeholders, believed at the time of the hearing that the LCFS should remain fuel-neutral. It was thought at the time that the inclusion of provisions for ultralow carbon fuels would create “winners and losers” within the program and make the LCFS less driven by market forces and performance and more driven by incentives and mandates. 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 incentivize higher volumes of these fuels to be used.

3. Incentives

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 will need to include special provisions to further encourage the development of ultralow carbon fuels. For that scenario, we have identified and discussed below several possibilities for incentivizing ultralow carbon fuels.

[Discussion of the several possibilities: multipliers, mandatory % of fuel pool consisting of ULCFs, specified shelf-life for credits achieved in early years, etc. Panelist input needed.]

However, as indicated above, we believe it is premature to recommend such adjustments given that the program is in its early stages. Further, if such incentives are proposed in the future, we would need to evaluate at that time the impacts the incentives may have on stakeholders.

At the meeting we discussed whether infrastructure investments should be held against RFS or LCFS. Without prejudging the conclusion of that discussion, I believe that it would be useful from the perspective of providing other states with information to support future harmonization to represent within the report the case where LCFS is considered as sitting 'on top of' RFS, as this would provide indication of the additional expense of imposing other regional LCFS on RFS.

Staff proposes to use this and similar outlines to develop the white papers/chapters of the review report due to the Board in December 2011. Please review this outline and identify where data are insufficient and what data are necessary to meet the requirements of the regulation review. This outline is meant to be a high-level overview of the topic; more detail will follow in subsequent white papers/chapters.

VIII. Economic Impacts (Topics 8 & 12)

A. Background on topic
   1. Introduction
      a. In 2009, staff estimated the costs of producing the petroleum-based fuels–gasoline, diesel, and CNG—and the costs of producing the lower-carbon-intensity (CI) transportation fuels that could be used in combination with petroleum fuels to meet the LCFS.
      b. The estimate of economic impacts of the LCFS was necessarily assumption-based.
      c. For the cost of producing cellulosic ethanol, staff used analyses conducted by the National Renewable Energy Lab (NREL) and updated the costs to 2007 dollars, also taking into account expected technological improvements.
      d. Staff utilized gasoline and diesel scenarios separately and individually.
      e. Staff used \$66 - \$88/bbl for the price of crude oil for 2010 – 2020, which came from the 2007 CEC Integrated Energy Policy Report (IEPR) and was the same used for the AB 32 Scoping Plan.
      f. Tax incentives were available and considered for ethanol and biodiesel.
      g. The results were a potential cost savings of \$0 - \$0.08 per gallon for Californians.
      h. Crude oil prices, production of low-CI fuels, and timing of alternative fuels penetration can greatly affect the cost of transportation fuels.
      i. The LCFS has no adverse effect on small businesses because regulated parties are mostly large businesses. The owners of fueling service stations are considered the small businesses, but since the

LCFS regulation does not mandate the installation of E85, CNG, and hydrogen dispensers at any specific fueling station, those owners who choose to invest in providing these fuels at their stations will do so with the expectation of recovering the costs and increasing profits.

j. Staff assumes that the refineries in the State will continue to operate at capacity, and they will become net exporters of CARBOB. The importers of the blendstocks, typically oil companies, will be impacted by the LCFS because these imported blendstocks that are used in the California transportation fuel market will receive a premium price over other markets.
k. The impact on the State was a potential overall savings, given the assumptions stated above. As a result of the requirements of federal RFS2, any infrastructure costs can be attributed to the federal program and not the LCFS.
l. No vehicle marginal production costs were included in the original economic analysis, as the LCFS does not mandate the use of specific vehicles. Additional ZEVs and FFVs will be in the market either through additional mandates or customer preference.

2. Purpose for revisiting this topic
   To address the Advisory Panel review requirements as stated in the LCFS Advisory Panel Draft Workplan (Version 1) the scope of each review shall include, at a minimum, consideration of the following areas: **(8) The LCFS program's impact on state revenues, consumers, and economic growth** and **(12) Significant economic issues; fuel adequacy, reliability, and supply issues; and environmental issues that have arisen.**

B. ARB methods of analysis
   1. Cost-effectiveness
      a. We will utilize the same economic analysis model as the original 2009 LCFS analysis, including, but not limited to, using the same scenarios for gasoline and diesel and no capital cost for bio-refineries because the latter is absorbed by the federal RFS2. ARB may develop a scenario that will discuss the cost of low carbon fuels assuming the RFS2 is unsuccessful.
      b. Update the feedstock production costs (i.e. higher costs for corn, woodchips, and MSW).
      c. Update the costs from 2007 dollars to the most recent available CEPCI (Chemical Engineering Plant Cost index).
      d. Remove all tax incentives for corn ethanol, cellulosic ethanol, and biodiesel. In the new analysis, ARB will assume that all the federal

subsidies that are due to expire at the end of 2011 will not be reinstated.

e. Increase the crude prices based on the 2011 IEPR high price case for the 2012 through 2020 periods (from $70 - $88 per bbl to $102 – $121). CEC may increase the high case by an additional $20/bbl in the near future and, if so, would be incorporated into our assessment.
f. Remove the infrastructure costs, as they are absorbed by the RFS2 program. These costs will be reinstated for the scenario in which RFS2 is unsuccessful.
g. ARB may explore a range of “safety valve” options that could be used to overcome compliance problems associated with a shortage of low-carbon fuels, a shortage of affordable credits, or both.

2. Impact on the State
   a. Update the state’s excise tax from the previously 18 cents/gal to the current 36 cents/gal.
   b. Remove the 9 cents/gal of State tax break for E-85.
   c. Develop a new Form 399 to show the impact on the State.
   d. Although most, if not all, of the low carbon fuels will be produced outside California, in the absence of federal subsidies and assuming new technology will progress slowly, the cost of low carbon fuels may rise to levels comparable to the cost of petroleum fuels or higher. After adjusting for the new crude oil prices, CARB will analyze any potential cost that consumers may incur.

C. Conclusions and Recommendations

Our conclusion will reflect analysis results and Panel discussions.

High Carbon Intensity Crude Oil (Topic 14) Draft Outline

Description of Issue:

The LCFS regulation requires regulated parties to use the carbon intensity (CI) values in the Lookup Tables associated with high-carbon-intensity crude oils (HCICOs) and to calculate and report the associated deficits from these sources (Section 95486(b)(2)(A)). The purpose of this requirement is to account for additional emissions generated beyond the 2006 gasoline and diesel baseline from the use of HCICOs and to encourage emission reduction activities from these sources. If those CI values have not yet been determined and published in the Lookup Tables, the regulated party is required to propose a new pathway for its HCICO and obtain approval of the Executive Officer. Since no CI values for HCICO yet exist in the Lookup Tables, regulated parties are required to develop CI values by using a technically rigorous methodology referenced elsewhere in the regulation.

When the Board approved the LCFS on April 23, 2009, it directed staff, through Resolution 09-31, to work with stakeholders to develop an informal screening process for assessing the carbon intensity of new or modified fuel pathways. Staff convened the Crude Screening Workgroup to address new fuel pathways for HCICOs. The intended outcome of the screening process was to identify those crudes which are clearly not HCICO, thereby reducing the number of crudes that would be subject to the more rigorous technical analyses. A screening process to implement Section 95486(b)(2)(A) is nearly complete and can be used together with an interim default CI value until more specific pathways for HCICOs are determined.

However, the regulated parties subject to the HCICO provision have requested that the 2006 baseline value be used for all CARBOB, gasoline or diesel fuel regardless of whether it entailed use of HCICO (i.e. no differentiation between the carbon intensities of crude oils). ARB staff has indicated its willingness to discuss alternative approaches and has been meeting with stakeholders to better understand concerns and to secure supporting documentation in an effort to identify potential alternative approaches.

The outline below for the portion of the Advisory Panel report that staff will present to the Board in December 2011contains these items: additional background information on the current regulation, including the need to address HCICOs; a brief description of five possible approaches that have come to our attention for addressing HCICOs; and a list of the types of data needed that would inform our decision-making process for choosing the most appropriate approach to addressing HCICO in the LCFS. However, as with other potential regulatory amendments ARB staff will initiate a parallel public process to discuss amendments for consideration by the Board at the end of the year. It is anticipated that among the recommended amendments will be adjustments to the HCICO provision.

Draft Outline of HCICO Chapter of 2011 Report to Board

A. Background

1. Regulation Requirements

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

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

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

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

Chris Malins 7/14/11 8:15 PM
Comment [1]: At risk of being pedantic, wouldn't it be the case that if innovative methods were used to keep the CI within 15g of the baseline then the fuel would never be classified as HCICO, but perhaps should be referred to as 'potential HCICO' in the context of screening?

2. Summary of Crude Screening workgroup process and progress.

3. Regulatory Advisory 10-04A.

4. Discussion of the need for a HCICO provision

B. Path Forward: Potential approaches for Regulation amendments or revisions will be considered and evaluated by ARB staff, stakeholders, and the Advisory Panel. Part C of this outline briefly discusses the proposed methodology for assessing these potential approaches. Staff's intention is to recommend one of these approaches (a variant of one of the below approaches or a different alternative yet to be identified) to the Board in December in the form of a regulation revision.

1. **Current Approach with amendments:** These amendments clarify the regulation requirements and provide details for implementation. Amendments are based on the draft Crude Screening proposal that has been used to generate the list of non-HCICO sources attached to Regulatory Advisory 10-04A. The amendments may:

a. Include Step 1 of the screening process to codify the method used to generate the non-HCICO list. This will be presented as a certification process allowing for Executive Officer approval of additions to the non-HCICO list.

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

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

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

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

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

Chris Malins 7/14/11 8:20 PM
Comment [2]: Because it doesn't associate increased emissions with the specific operator related to them. this approach would effectively weaken or strengthen the compliance schedule for alternative fuels without affecting crude choice or processing. I believe that there is little advantage to altering the difficulty of compliance somewhat unpredictably in this way.

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

b. California Average Incremental Deficit: For the California crude refining industry:

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

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

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

Chris Malins 7/14/11 8:20 PM
Comment [3]: This provision, if effectively specified, seems like a constructive addition.

3. **Hybrid California Average/Company Specific approach:** The base deficit for individual companies is calculated the same as in the current approach. However, individual companies only incur an Incremental Deficit if their own crude slate becomes more carbon intensive over time relative to their crude slate refined in the baseline year. This allows for individual companies to shift the crude slate they refine in California and not be penalized as long as the average CI of their own crude slate does not increase.

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

   b. Company-Specific Incremental Deficit (Approach A): For each oil company:

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

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

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

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

   c. Company-Specific Incremental Deficit (Approach B): For each oil company:

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

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

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

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

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

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

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

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

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

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

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

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

Chris Malins 7/15/11 9:52 AM
Comment [4]: I would support using a mechanism such as this to give companies the opportunity to use upstream improvements to achieve part of compliance, and to prevent slippage in the CI of the crude slate.

Chris Malins 7/14/11 8:57 PM
Comment [5]: There seems to be little benefit to effectively relating the stringency of the compliance schedule to the worldwide average crude CI, compared to making it entirely independent of crude oil CI. I suggest that ay decision to make the compliance schedule more or less ambitious should be taken explicitly. It also seems to impose a burden of data collection on CARB which has little benefit.

b. Worldwide Average Incremental Deficit:

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

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

C. Issues to consider when evaluating the alternatives: This section will provide an evaluation of the "pros and cons" of the current HCICO provision and proposed alternatives with respect to the issues listed below. This evaluation will require a significant amount of data and analysis to be provided by California refiners with regard to their historic, current, and projected crude slates, costs for crude purchase from each source, constraints and barriers to changing crude slates, etc. This data for each refinery has already been requested by ARB staff.

1. Accurately accounting for emissions from production of crude oil used by California refineries.

2. Potential for crude shuffling to generate credits, avoid deficits, or otherwise comply with the regulation.

3. Market signal generated and/or direct incentive given for reducing GHG emissions from crude production and promoting the use of innovative methods for emission reduction.

4. Potential impact on criteria pollutant emissions from refining in California

5. Potential cost impacts to California refineries, oil producers, and consumers

6. Potential fuel supply impacts

7. Consistency with LCA methodology used for other fuels and fairness versus other fuel providers

8. Requirements for implementation and data availability for calculations

9. Simplicity of methodology (e.g., availability of data, ease of application)

Comments on credit trading:

I would suggest that a credit trading system should be as simple as possible , and arranged to meet these principles:

- Minimise transaction costs to all parties (especially those dealing in smaller numbers of certificates)
- Robust against fraud
- Some transparency (market information about credit value)
- Supports the involvement of brokers

As I have noted at meetings, I think that a specific consideration of the ability of smaller participants (which could be companies with a static and relatively small market participation, or companies entering the market with the intention to expand) to access credit value would be beneficial.

CREDIT TRADING OUTLINE

The purpose of this outline is to inform panelists of staff's initial findings and analysis related to the credit trading under the LCFS. A key element of the program is the provision to generate, bank, and sell credits. The provision establishes a market for LCFS credits thus requiring the need to track the accrual of credits, as well as their retirement or sale under the program. However, tracking these transactions requires the establishment or expansion of tools that the ARB is developing. It will also require that certain provisions in the regulation be further clarified. The purpose of this outline is to provide background on the existing LCFS regulatory requirements with respect to credit trading, consider other credit trading programs including any lessons learned, and identify key themes that ought be considered with respect to the LCFS credit trading system. The Panel's perspectives on what makes a robust credit trading system will help to inform recommendations that the ARB develops.

Staff proposes to use this and similar outlines to develop the white papers/chapters of the review report due to the Board in December 2011. Please review this outline and identify where data are insufficient and what data are necessary to meet the requirements of the regulation review. This outline is meant to be a high-level overview of the topic; more detail will follow in subsequent white papers/chapters.

I. Introduction
   A. This topic added in response to panelist comments regarding the importance of the development of the credit market.
   B. Focuses on both near- and long-term solutions to building a functioning credit market
   C. Background on regulatory requirements
   D. Background on other credit trading programs (lessons learned)
   E. Summary of any Panel findings

II. Key Considerations for Trading
   A. Objective
      1. Develop a viable credit trading system
      2. Ensure the ability to monitor and evaluate the health of the market
   B. Role of Market
   C. Role of ARB
   D. Transparency
      1. Information needed for the credit market to function
      2. Information to be made available to the public
      3. Information that will remain confidential
   E. Monitoring
      1. Ensuring credit trading is a competitive exchange
      2. Protection from fraudulent use of the system
   F. Ensure longevity and robustness in the credit trading market

III. Summary of Potential Regulatory Options
   A. LCFS Credit Banking and Trading
      1. Proposed new a new section to the LCFS regulation
      2. Provides regulatory provisions on how credits are banked and traded within the LCFS program
      3. Also provides information on how credit balances are calculated and banked for each reporting quarter
      4. Will give direction on reporting requirements for trades and the process of reporting to ARB
      5. Will contain concepts including credit carry-back and credit retirement hierarchy
      6. Key concepts include: transferrable credits, credit trading, credit retirement, and public disclosure of information.

IV. Conclusions